BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

CONSENT MARKETS, TARIFFS AND RATES - ELECTRIC :

CONSENT MARKETS, TARIFFS AND RATES - GAS :

CONSENT ENERGY PROJECTS - HYDRO :

CONSENT ENERGY PROJECTS - CERTIFICATES :

DISCUSSION ITEMS :

STRUCK ITEMS :

- -x

COMMISSION MEETING - 799TH REGULAR MEETING

OPEN SESSION

Hearing Room 2 C

Federal Energy Regulatory

Commission

888 First Street, N.E.

Washington, D.C.

Wednesday, July 17, 2002

10:00 a.m.

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APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN PAT WOOD, III, Presiding

COMMISSIONER LINDA KEY BREATHITT

COMMISSIONER NORA MEAD BROWNELL

COMMISSIONER WILLIAM L. MASSEY

SECRETARY MAGALIE ROMAN SALAS

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APPEARANCES (CONTINUED):

RICHARD BULLEY, Executive Director, Mid-America Interconnected Network, Inc.

TOM KRAYNAK, Manager of Operations and Resources, East Central Area Reliability Coordination Agreement

DEREK COWBOURNE, Chairman of Operating Committee, North American Electric Reliability Council, (NERC)

MIKE GENT, President and CEO, North American Electric Reliability Council, (NERC)

JAMES TORGERSON, President and CEO, Midwest Independent System Operator, Inc., (MISO)

DR. DAVID PATTON, Potomac Economics

BILL PHILLIPS, Vice President of Operations, Midwest Independent System Operator, Inc., (MISO)

MICHAEL KORMOS, Executive Director of System Operations, PJM Interconnection, LLC

NICK WINSER, Senior Vice President, National Grid, USA

ELIZABETH A. MOLER, Senior Vice President, Exelon Corporation

KATHRYN L. PATTON, Senior Vice President and General Counsel, Illinois Power Company

J. CRAIG BAKER, Senior Vice President, Regulations and Public Policy, American Electric Power Service Corporation

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APPEARANCES (CONTINUED):

MIKE MC LAUGHLIN, Federal Energy Regulatory Commission

WILLIAM MUSELER, President and CEO, New York ISO

DAVE LA PLANTE, Vice President of Markets Development, ISO-New England

CHARLES KING, Vice President, Market Services for New York ISO

JOHN MC PHERSON, Federal Energy Regulatory Commission

STEVE ROGERS, Federal Energy Regulatory Commission

ERICA YANOFF

ROBERT CHRISTIN

INGRID OLSON

JACKSON FRAY

KERRY NOONE

JOHN CARLSON

MIKE MC GEHEE

LAUREN O'DONNELL

JOHN MYLER

BILL HEDERMAN

DAVID LEGENFELDER

CAMILLA NG

BRIAN HARRINGTON

MEESHA BOND

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APPEARANCES (CONTINUED):

JEFF WRIGHT

J.B. SHIPLEY

COLIN MOUNT

LEONARD TAU

EUGENE GRACE

GARY COHEN

ALSO PRESENT:

DAVID L. HOFFMAN, Court Reporter

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P R O C E E D I N G S

(10:00)

CHAIRMAN WOOD: Good morning. This open meeting of the Federal Energy Regulatory Commission will come to order to consider the matters which have been posted in accordance with the government in the Sunshine Act for July 17, 2002 at this place. And since we're not in the Ninth Circuit, I think it's okay for us to stand up and give the full Pledge of Allegiance.

(Laughter.)

(Pledge of Allegiance recited.)

CHAIRMAN WOOD: Madame Secretary?

SECRETARY SALAS: Good morning, Mr. Chairman, good morning, Commissioners. The items that have been struck since the announcement of the Sunshine Notice on July the 10th, as follows: E-14, E-21, E-27, E-31, E-33, E-35, E-45, E-46, G-18, M-1, M-2, G-20, and C-2.

Your consent agenda for this morning is as follows: Electric items E-2, E-4, E-5, E-6, E-8, E-9, E-12, E-13, E-15, E-16, E-18, E-19, E-20, E-22, E-23, E-24, E-26, E-28, E-29, E-30, E-32, E-34, E-37, E-38, E-39, E-41, E-42, E-43, E-44, E-47, E-52, E-53 and E-54.

Gas items G-2, G-3, G-5, G-6, G-7, G-8, G-9, G-10, G-11, G-12, G-13, G-15, G-16, G-19, G-20, G-22, G-23 and G-24.

Hydro, H-2, -3, -6, and -7.

Certificates C-3 and C-4.

The specific votes for some of these items are as follows: E-34, Commissioner Massey dissenting in part with a separate statement. G-2 Commissioner Brownell concurring with a separate statement. G-19 Commissioner Brownell concurring with a separate statement, and Commissioner Massey votes first this morning.

COMMISSIONER MASSEY: Aye, with my dissent in part on E-34.

COMMISSIONER BREATHITT: Aye.

COMMISSIONER BROWNELL: Aye with my concurrences on G-2 and G-19.

CHAIRMAN WOOD: Aye. I want to thank all the advisory staff and all of our back bench staff here for the work in getting through a pretty substantial agenda. Hold that thought. We've got another one coming. But I appreciate the fine work that it took to get through a substantial amount of decisions that I know the folks in the industry and the parties outside are waiting for. So thank you for your hard work.

SECRETARY SALAS: The first item in your discussion agenda this morning is G-4, Atlantic Gas Light Company. The presentation by Erica Yanoff and Robert

Christin.

MS. YANOFF: Good morning. This item addresses a petition by Indicated Marketers for clarification or limited waiver regarding Atlantic Gas Light Company's allocation and release of certain Part 157 and Part 284 transportation and storage capacity on upstream interstate pipelines to Georgia marketers under a Georgia Public Service Commission tariff. The petition requests that the Commission clarify that Atlanta may use this upstream interstate capacity as part of its Georgia PSC tariff or, alternatively, grant the necessary Natural Gas Act certificate authorization and waivers to permit Atlanta to allocate and release such interstate capacity to the marketers. The order denies the requested clarification since the Commission cannot grant a request that it deferred to state regulation and services utilizing capacity over which the Commission has jurisdiction.

However, the order grants Atlanta a limited term, limited jurisdiction Natural Gas Act certificate and temporary waiver of the Commission's shipper must have title policy and reauthorizes the previously effective incremental bundled storage service ideas as rate schedule based on the finding that such action is in the public interest to avoid delay in the injection of gas supply into storage for the 2002-2003 hearing season. Certificate and waiver granted by the order will expire on March 31st, 2003.

The order also directs Atlanta to show cause why it should not be found to have been allocating and releasing upstream interstate capacity without the requisite certificate authority in violation of the Natural Gas Act since the expiration of its idea says rate schedule on March 31st, 2001.

Finally, the order additionally directs Atlanta and the upstream interstate pipelines to show cause under Section 5 of the Natural Gas Act why the Commission should not require that the Part 157 certificate be used to provide service on behalf of Atlanta be converted to Part 284 certificates.

Thank you.

CHAIRMAN WOOD: Any commentary on that?

COMMISSIONER MASSEY: I have a question. Is there any reason why this state unbundling program would not work under Part 284 Certificates. I know we're going to issue an order showing cause and we'll ask for comment on that, but I just wondered what your initial thinking is about it.

MR. CHRISTIN: Do you mean if the state, would the state be regulating it under --

COMMISSIONER MASSEY: No. Will the marketers be able to get the capacity they need for this program to work under Part 284 certificates?

MS. GRANSEE: Commissioner, there's no reason we know of that it shouldn't work.

COMMISSIONER MASSEY: So they could invert to a Part 284 open access program and this program should work?

MS. GRANSEE: Yes.

COMMISSIONER MASSEY: Now, we've asked for a comment on it, and we've given them an additional extension. We've given a number of extensions over the years and this is one more. But we have no reason to believe that it wouldn't work under Part 284 conversion.

MS. GRANSEE: That's correct.

COMMISSIONER MASSEY: Okay. That answers my question. Thank you.

CHAIRMAN WOOD: That's done.

COMMISSIONER MASSEY: Aye.

COMMISSIONER BREATHITT: Aye.

COMMISSIONER BROWNELL: Aye.

CHAIRMAN WOOD: Aye. Thank you all.

SECRETARY SALAS: The next item is G-14, Maritimes of the Northeast Pipeline with a presentation by Ingrid Olson, Jackson Fray, and Kerry Noone.

MS. OLSON: Good morning, Mr. Chairman and Commissioners. G-14 Maritimes on Northeast Pipelines sets under for hearing under Section 5 of the Natural Gas Act issues raised by cost in revenue study filed in Maritimes.

In July 1997, the Commission issued Maritimes a certificate authorizing it to transport natural gas and approving initial rates for that service. The Commission directed Maritimes to make a filing by December 31st, 2001, either to justify its initial rates or propose alternative rates. Maritimes filed a cost and revenue study to justify its rates on December 27th, 2001. In an order issued April 25th, 2002, the Commission found the study to be deficient and directed Maritimes to file information consistent with the Commission's orders issuing the certificates.

On May 17th, Maritimes made a filing that included the schedules and information required by the Commission. The draft order concludes that upon review of the cost and revenue study, a hearing should be convened to determine whether Maritime's rates are just and reasonable, and clarifies that the proceeding is pursuant to Section 5 of the Natural Gas Act. Thank you.

CHAIRMAN WOOD: The reason why I wanted to mention this one separate was I think since I've been here, this is the first Section 5 rate case that we have initiated as a Commission, so it's appropriate here. As to this particular case, I think with a new pipeline, we've already got some initial numbers from the filing that was required as part of the original certificate. I think this can be a pretty straightforward revenue requirement rate design case and I strongly urge our trial staff and the parties to move through this in a rapid, swift manner settling issues as much as possible.

I think, when I look at my own personal history, and my very first appearance before FERC as a private attorney, it was in a rate case that I think all-in-all took about 38 months from start to stop. Needless to say, I changed jobs in between and came to FERC, but we do need to demonstrate that we can actually move in a pretty swift and rapid manner here.

Without a whole lot of further commentary, I would urge our staff to take a leadership role in that regard. Section 5s in general I do think I've made the point that we have a number of shippers that are increasingly coming in, and I've urged the Commission to examine the earned returns of the regulated interstate pipelines and ask us to take action rather than wait for shipper filed complaints to do so. I've heard those concerns. My general thought is I've shared this with folks over at INGAA and with the shippers that come in, that so long as pipelines are expanding and investing in expanding their pipeline plant and making investments to broaden and increase the needed transmission highway for natural gas, even if they are over earning, I'm less inclined to support initiating an action unless it's way out of line. Those pipes that may not be plowing their earnings back into pipeline planning and expanding across the nation, I would say that would certainly be an area that we might look at.

That's about all I have to say, but there's certainly need for additional expense in our pipeline grid. I'm certainly pleased that the policies that the Commission adopted in the past decade really send a pretty clear signal about how you recover the investment once you make it. I hope we can get that clarity on the electric side as we talk through the issues in the NOPR FAR next meeting. I do think it's important to let pipes know that that's very important to us and has carrots and sticks attached to that. Certainly this case provides that opportunity to make that point publicly.

On the order, any thoughts?

COMMISSIONER BREATHITT: I just agree with a lot o your sentiments.

CHAIRMAN WOOD: Do you want to vote?

COMMISSIONER MASSEY: Aye.

COMMISSIONER BREATHITT: Aye.

COMMISSIONER BROWNELL: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: The next item for discussion is

G-17 El Paso Natural Gas Company.

CHAIRMAN WOOD: In lieu of a presentation here, I thought I'd just give a brief discussion about why this is posted. We had considered some different issues responding to different pleadings in this case. I believe we've agreed not to do that. I know Linda had some thoughts on that, and I'll just turn it over to Linda.

COMMISSIONER BREATHITT: We certainly have a very important deadline looming on a matter that we spent a day on about six or eight weeks ago with respect to the El Paso situation in the Southwest and the West. We have two very critical important weeks left in the time that we gave the parties to try to resolve these very critical and important issues in that part of the country where there is a lot of competition for gas supply.

My thoughts on that are the parties need to be well aware that they have roughly 14 days left and that if there is not resolution made, that we do have a full array of options before us to consider taking that matter into our own hands. So I urge to take full advantage of the remaining weeks that they have to do this on their own terms and conditions rather than having a full array of options before us and we do that.

CHAIRMAN WOOD: All I've got to add to that is Amen.

COMMISSIONER BROWNELL: I'd just like to add, and thank you, Linda, for actually giving some thought to this, and your leadership. If ever there were a case that demonstrated the need for regional cooperation, it is this one. I was pleased that immediately after our last meeting, the Chair of the Arizona Commission wrote to the chair of the California Commission saying that they wanted to sit down and wanted to cooperate. I would hope that that is in fact happening. I think it is in no one's best interest to be fighting over scarce resources in a way that is parochial. It simply does not bode well for the region and the needs of the region which I think we'll see quite clearly demonstrated in a report coming later.

COMMISSIONER MASSEY: I'm glad we're having this discussion. This has been a festering problem that we need to resolve as quickly as we can, so I would like to echo Linda's comments and simply restate for the record that the Commission is very serious about solving the problems that this case presents to us, and will act forcefully when necessary to do so.

CHAIRMAN WOOD: Enough said. So there'll be no order on G-17, we'll move on.

SECRETARY SALAS: The next item for discussion is G-21, Transwestern Pipeline Company with a presentation by John Carlson.

MR. CARLSON: Good morning, Mr. Chairman, Commissioners. Before you is a draft order relating to several Transwestern pipeline company negotiated rate transactions that date to the winter heating season of 2000-2001. These negotiated rate transactions required shippers to pay transportation rates based on natural gas spot market price differentials between the California border and the production basins. The rates under the agreements exceeded the Commission-approved cost-based rates by many multiples. The draft order finds that Transwestern violated its tariff and Commission regulations with respect to the Sempra Energy Trading and Richardson Products Company contracts by negotiating the initial transactions prior to posting the capacity as being available on its Website.

Additionally, the draft order finds that Transwestern violated its tariff and Commission regulations by selling interruptible service as firm service. The order requires Transwestern to return its profits from the transactions. Additionally, the order suspends Transwestern's authority to negotiate rates using pricing differentials for new transactions for a period of one year. Additionally, the order requires Transwestern to modify its tariff and its Websites to clarify its posting and capacity allocation procedures. There are additional transactions that have been accepted, subject to the outcome of this proceeding and Staff will obtain additional information on these deals to see if there are similar violations of the tariff regulations. This concludes my presentation. Thank you.

CHAIRMAN WOOD: John, on that last point, you referring to a number of companion dockets that said whatever happens here, that's the acceptance of negotiated rates between Transwestern and other customers would be subject to this docket. Is that what you're referring to?

MR. CARLSON: Yes.

CHAIRMAN WOOD: So we would look for whether there's information related to the same kind of --

MR. CARLSON: Right. What we would primarily be looking for is contract information that would indicate whether the deals were interruptible capacity being sold as firm. That's primarily what we're going after. What we would be looking for and get information about Transwestern to see if in fact the capacity that was sold under those transactions was the operationally available capacity that it couldn't guarantee every day of the market.

CHAIRMAN WOOD: As to the remedies recommended in the order here, the difference between the recourse rate and what was actually billed to the customer will be treated how?

MR. CARLSON: It will be flowed back or refunded to all shippers on the system, firm shippers presumably based on their contract demands and to interruptible shippers based on their usage during those time frames to the extent that there was any during that time frame.

CHAIRMAN WOOD: I'm disappointed at the violations of the tariff by this pipeline and I think that that kind of behavior undermines the relatively good record of compliance by the pipeline industry in general over the last decade that we've had unbundled transportation. One of the things that concerns me about beyond the violations there, that concerns me about the nature of these transactions, now that we've had the chance to explore those in the hearing and understand them better is that you really are putting the pipeline back in the business that we worked so hard to get them out of in 436, 500, and 636, which is having a vested interest in what's going on in the commodity market. They're supposed to be a straight transportation only business that worries about transport. These bills put them back in the saddle very directly in a relatively overt way of issues in the commodity market.

I don't think that's where we want to go. I understand in our consent agenda, we approved a series of questions, notices of inquiry, on the negotiated rate policy in general and asked questions about these types of issues and other issues. And I do look forward to moving forward on that as soon as we can to try to maybe, if necessary, head this off at the pass. But I'm disappointed in the behavior here, very much so. And think that the remedy is appropriate at this time, and look forward to further developments on the policy front as we learn a little bit more about the other type of negotiated deals.

COMMISSIONER MASSEY: Just for the record, could you set out what the regulated rate was versus the range of rates that were based on the basis differential?

MR. CARLSON: The regulated rate was 38 cents per decatherm on a daily basis. The price differentials during this time period approached $35 to $36 on certain dates but were in excess of, at least for the first month of the transaction, in excess of five dollars every day.

COMMISSIONER MASSEY: So sometimes a hundred times greater than the regulated rate.

MR. CARLSON: Yes.

COMMISSIONER MASSEY: I'm glad Chairman Wood supported out the Notice of Inquiry that we have voted out. I think this provides a good opportunity for the Commission to ask some questions about the negotiated rate program, revisit it and decide what our policy should be moving forward. Thank you.

CHAIRMAN WOOD: Before Linda speaks -- I was sitting on that side of Linda back in July. I think that it was in July that this was set for hearing when you discussed this at some length in what was a relatively bloodless, uninformative Order. You gave it a lot of life, and I appreciate your sharp eye on that, and wish we hadn't found anything.

But I think that's what we do, look for it and call it like we see it.

COMMISSIONER BREATHITT: I just have one more point to add, and I just want to make sure that the comment that I'm making is factually correct, along the lines of the results of this Order. And that is that the Order requires certain changes to the posting of daily capacity, and that the changes should help eliminate confusion and possible discriminatory results. Is that the changing of the daily?

MR. CARLSON: Yes.

COMMISSIONER BREATHITT: As the Chairman said, we had this before us for a year, and we set this matter for hearing. Now you're seeing the results of that, and I think that the Order is a good one, in that it brings equity to the parties.

We looked at this at that time, because there was so much tension on high gas prices in California, and this was just glaring in the basis differentials, to me and to all of us, because were all here then. So, thanks.

CHAIRMAN WOOD: I just think that when you've got a market, the end use product, as has been discussed for years, and we'll talk about again later today, the end use product of this market was really subject to no sort of check by any customer.

These people that bought at a hundredfold, the recourse rate gas through these pipelines, had little incentive to manage the price, because they could just pass it on into a very energy-starved electricity market.

When you've got the wrong incentives all in place, and you put a monopoly provider in the saddle, being able to extract some profit in excess of a cost-based rate, with good return on equity already dumped into it, boy, we're in trouble.

I do think this is a problem, and I'm really looking forward to parties reactions, maybe, to the contrary, parties reactions, nonetheless, and our Notice of Inquiry on it. So, we're ready to vote.

COMMISSIONER MASSEY: Aye.

COMMISSIONER BREATHITT: Aye.

COMMISSIONER BROWNELL: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: The next item for discussion this morning is C-5, Kern River Gas Transmission Company, with a presentation by Mike McGehee, Lauren O'Donnell, and John Myler.

MR. McGEHEE: Good morning, Mr. Chairman and Commissioners. I'm Mike McGehee, and with me are Lauren O'Donnell and John Myler. The other members of the team not at the table are Ken Newhouse, Mike Boyle, Lew Reed, and Audrey Long.

I'd like to point out that it's mainly due to the efforts of our Environmental Project Manager, Mike Boyle, that this item is for consideration today. I have a PowerPoint presentation.

(Slide.)

MR. McGEHEE: Item C-5 is an order that will grant Kern River a certificate to construct its 2003 expansion project. Next slide, please.

(Slide.)

MR. McGEHEE: This map depicts the new facilities that Kern River proposes to add to its system. The slide gives you an idea of the project's scope and the terrain encountered.

Kern River's project will add new pipe along 80 percent of its existing system.

Next slide, please.

(Slide.)

MR. McGEHEE: Kern River will construct over 700 miles of pipe and three new compressor stations. In addition, Kern River will install additional horsepower at six existing compressor stations, all at a projected cost of $1.2 billion.

The project will add over 885 Mmcf of new capacity, which, in effect, doubles Kern River's existing capacity to 1.7 Bcf a day. Next slide, please.

(Slide.)

MR. McGEHEE: The Commission's preliminary determination, issued on February 27, 2002, pointed out the significant benefits associated with this project. For example, the project will allow western LDCs to meet the critical peak needs and will deliver natural gas to a number of new electric generation plants that were located near the project's path. Next slide, please.

(Slide.)

MR. McGEHEE: This slide will be discussed by Staff later on in the meeting in Item A-3, the Western Market and Infrastructure Assessment. The slide identifies the new plants coming online in the Western Electricity Coordinating Council.

Kern River's project will serve approximately 30 percent of the new generation coming online in the Southwestern California Region. Next slide, please.

(Slide.)

MR. McGEHEE: This slide shows the location of the new plants that will be directly dependent upon Kern River's expanded capacity. The collective generation capacity of these plants will be approximately 6,700 megawatts. Kern River's expanded capacity will also be used to indirectly serve new electric generation located in areas served by California's intrastate systems. Next slide.

(Slide.)

MR. McGEHEE: There are other benefits to the expansion, as well. For example, the project will add much needed take-away capacity to the Central Rocky Mountain Production area. Kern River's application included at study showing a widening gap between gas production and take-away capacity in this area.

According to that study, the rate of gas production in the Central Rockies will increase by almost

Bcf a day over the next five years, while the planned increased pipeline take-away capacity is only 1.7 Bcf a day.

This project will benefit the Central Rocky Mountain area by helping foster significant economic development. Last slide, please.

(Slide.)

MR. McGEHEE: The environmental review for this project was completed in less than one year, in part, because this project was the first to take advantage of a NEPA pre-filing process, adopted by the Commission. Typically, it takes up to 16 months for the environmental review to be completed for a project of this size.

It's also interesting to note that it took 30 months to issue the IES that included the initial Kern River System. The 11-month timeframe was also obtained as a result of the excellent cooperation between the various federal and state agencies who were involved in this project.

The prefiling process facilitates this cooperation by starting the required interactions in a much earlier timeframe.

In conclusion, this project will add needed infrastructure that will serve the growing markets of California and Nevada. Kern River's 2003 expansion project will be a major step toward meeting that need. Thank you.

CHAIRMAN WOOD: Thank you, Mike. There's a report in Gas Daily today that talks about a report that came out yesterday from the Rand Corporation, talking about the demand and supply of natural gas, which we'll see in a moment in the Western Infrastructure update.

But there's -- it mentions here that there is considerable evidence of the current pipeline infrastructure operating very close to capacity and that plans for interstate pipeline expansion may lag behind expected demand growth. Expansion plans for interstate capacity will at best, on marginal requirements, anticipate demand growth throughout the West.

I think we see more projects like this, and I do think they are a little more welcome today and a little easier to do because of the way out of the box that you all showed that we can move a major, over $1 billion investment that runs over four states in pretty substantially quick time, because of the administrative changes that have been made at this Agency, and also a willing applicant that wants to get in and make some investment.

So I think it's a nice mix of things that I will hope will prove the Rand report to be unusually pessimistic. Nonetheless, they are needed, and I'm pleased to see and to congratulate the proponents from Kern and their customers for working together to get to this round so quick.

It's actually the first one that's come and gone since you and I have both been here, so we've been here a long time. Jump for joy and I'll buy you lunch. Congratulations.

I want to thank the team here for the presentation and for all the work behind the scenes to get it done and to get it done well. It was a well-done FEIS, too. Let's vote.

COMMISSIONER MASSEY: Aye.

COMMISSIONER BREATHITT: Aye.

COMMISSIONER BROWNELL: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: The next item is A-2, Customer Matters - Reliability in Market Operations, more specifically, an Assessment of Summer Market Conditions. It is a presentation by Mr. Bill Hederman, Director of the Commission's Office of Market Oversight and Investigations.

MR. HEDERMAN: Good morning, Mr. Chairman and Commissioners. Thank you for the opportunity to present this first analytic effort from our new office.

I'm sitting up here alone, but there are well more than a dozen people that helped to put this together. Rather than read the list to you now, we'll make sure that you know who has helped to put this together, later.

But what I wanted to review with you today is an internal analysis that we prepared on energy markets.

(Slide.)

MR. HEDERMAN: Looking at this time in the mid-Summer, we took both a national and a regional perspective. We have reviewed the improvements in each of the markets, noted the concerns, and then drawn items for OMOIs action down the road from here.

In the future, we hope to be able to address these matters and develop this assessment before the cooling season starts and before the heating season starts. But with our startup, of course, that wasn't possible this first time.

Overall, I think our assessment is that the electricity markets are in fair to good condition. I would use "okay" as a general adjective for describing the situation. There have been reserve margin improvements, and generally they're in better shape than they were the prior cooling season, but that includes capacity-rich areas and capacity-short areas.

Demand responsiveness has improved a little bit, but progress there remains quite disappointing. There is some additional electricity transmission infrastructure in place; much more is required.

On the point of regional energy markets, I'm sure we've all seen that progress has been made there, but lots of work remains to be done in the area of market design at the ISO and RTO level. There has been progress, but now we have to look at those transitions.

Of course, all that will change very soon, as the Commission puts forward the national standard market design. I think our main concerns on the national level are the financial health of the participants which continues to weaken. That's something that we need to pay attention to.

The weakness affects both liquidity in the markets and also affects the extent to which there are players. And you need more players to have competition.

There's also a concern that transitioning markets are particularly vulnerable to both extreme weather and security threats. We intend to keep an eye on that and address those analytically, to the extent analysis can help and to the extent there is some unfavorable event to be watching the market implications of that.

There have been some generator availability issues that we're keeping an eye on. There are the nuclear issues. There's a recent develop on new gas-fired combined-cycle availability issues in the Northeast where it's been much lower than one would expect, and we will be keeping an eye on that, trying to understand the factors contributing, and keeping you informed on that.

As I mentioned earlier on the changes in market design at the ISO level, there is the potential for unintended consequences as we walk through some of the regions. I think you might see some of those. In market surveillance discussions, you'll hear about those as well, and we're keeping an eye on those.

In terms of OMOI's overall approach, we will be monitoring market performance issues. We will be closely coordinating our monitoring with ongoing investigations with Commission Staff and also with the efforts of the market monitoring units.

I think we're building good working relations there, and we're looking forward to making them even more effective. We'll be providing you with periodic updates, and to the extent there is a major unexpected market development, we will be putting mechanisms in place to make sure you know as much as we know, as soon as we can.

The first region I wanted to discuss with you is the West. I will not go through the details of our concerns there. I think you'll hear far more detail about them in the discussion from the Western Infrastructure Group.

But I did want to review the actions that we see falling out of what's observed there at this point. One is, there is a need to keep an eye on this region. It's the area of greatest risk of instability, and we will be actively monitoring what's going on there, both from the market and physical reliability issues.

As we've discussed, we think that Staff's presence at the Cal ISO, working closely with the market monitors will help the Commission get on top of this and stay on top of what's going on there.

Certainly, to the extent that there continues to be need for special mitigation measures, there probably is a need for Staff presence, both from us and from OMTR. We will also suggest that we look at the possibility of another technical conference out there to look at the issues going forward, identifying who needs to be doing what, what's in the area of the Commission? What's the responsibility of the ISO or the state, or regional issues?

We will explore that, to the extent that the Commission believes that's a good idea, with the parties out there, and proceed, if it looks like it can be fruitful.

The next area of the country that we'd like to turn to -- and we are addressing this in roughly the order of concerns -- is the Southeast. The situation there also represents some improvement.

There has been some addition of merchant generators and some online. There have also been some investments and additions of capacity in the gas and power transmission side.

But despite those physical improvements, the region requires further maturity to reach a level of development that allows workable competition.

(Slide.)

MR. HEDERMAN: The concerns there relate to a lack of progress in developing the broad, regional markets. There are transmission service quality issues. In particular, probably the area where the most complaints about access, and there are some specific transmission constraints there, both at the Georgia-Florida border, and within some subregions in Entegy, to name a couple.

There also is some concern related to forecast weather, to the extent that weather forecasts can tell us anything useful.

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There is an issue there, and drought conditions in particular affecting both hydro availability and also is the matter -- and you'll hear this in the Northeast as well -- of cooling water for other plants. OMOI intends to continue to monitor the progress on Dominion, and in particular its integration into PJM to draw lessons there about integration.

When we turn to the Midwest, you'll see that some new seams issues can arise as areas expand, and we'll keep an eye on that.

We'll be monitoring compliance with the Commission's open access tariff requirements and with generation interconnection policies and we'll be stepping up examinations of alleged patterns of reported negative behavior.

We also are planning, if you will, a product introduction marketing effort on the hotline, if you will, with the Southeast as a test market, to make sure people are aware that the hotline is there and if they're having problems gaining access or with other market-related issues, they know there's an easy way to pick up the phone and toll free let the Commission know about it.

(Slide.)

Turning to the Northeast, this is another area with some improvements but also some concerns. The supplies on line. The ISOs have addressed some of their transmission constraint issues and improved the market rules under which things are operating, and the new rules seem to be improving market behavior and performance, but there's still things to be done there.

The issue of Ontario has arisen in terms of there's some unexpected flows there as Ontario is needed to draw on the U.S. markets. And there was some transmission load relief measures taken around there, and we're keeping our eye on that. In fact, we'll be having conversations with some of the monitors in Ontario soon.

Here we intend to be focusing on the load pockets and looking at the possibility for the exercise of market power in those load pockets. The southwest Connecticut area is one that has received special attention from OMTR and OMOI staff and will continue to.

We are looking at how the market mitigation issue can affect investment in the areas where the mitigation measures need to take place, and we'll be keeping an eye on that, and as I mentioned, looking at the unexpected effects of some of the market rule changes.

Also we'll be addressing the seams issues along the ISOs, and we are seeing, for example, that some of these seams issues can move to the new boundaries.

(Slide.)

If you look at the PJM West area, for example, with some of the generation assets being outside of the PJM dispatch, there have been some TLR measures because the seam moved to include a PS.

Let me speak briefly then to the last region that I'm covering today, the Midwest. Also we're going to hear a lot more about that soon. I think that the Midwest in general looks healthy with strong fundamentals. There is a substantial addition ECAR/MAIN on the supply side and the parties are trying to move forward here on joining RTOs, and working through that process remains a challenge that I think OMOI will need to be following along with many other parts of the Commission and others.

Among the concerns we have there are the final shape and size of the RTOs relevant there. We are following the TLR activities. One I haven't mentioned yet is the Upper Michigan Wisconsin area where there have been some flow issues. They also relate to who's dispatching what, but they've had minor market consequences, but we are keeping an eye on that.

The MISO export fees have not helped, but the discounts have. It's our intent there to be monitoring the development of the RTO. No surprise there. We'll be monitoring the related seams issues that developed and the

TLR implications.

And that pretty much is a quick pass at what we see in terms of a work plan for us going forward based on the summer assessment. Thank you for your attention. I'll be happy to take any questions.

CHAIRMAN WOOD: Bill, thank you for the speed with which you've gotten the office up and operational. You've made some internal decisions and others are coming, both internal and external. I appreciate the thoughtfulness that you and your steering team have handled setting up the shop.

As to the substance here, the only question I have I wanted to ask you to flesh out a little bit more because it was new to me, was the generator availability issue related to gas CCCTs in the Northeast. What's going on there?

MR. HEDERMAN: We've gotten a couple of reports that the availability factors have been unusually low, in the 30 percent range for some of those units. We're still trying to find out what's going on there.

CHAIRMAN WOOD: Newer ones or older ones?

MR. HEDERMAN: They're new units. Whether there's some special reasons for the startup problems, whether it's a particular type of equipment we haven't been able to find that out. but we were able to find a couple of reports that this was in fact happening.

CHAIRMAN WOOD: Availability when they were actually needed for dispatch purposes?

MR. HEDERMAN: No. There was no sense that there were market implications at this point.

CHAIRMAN WOOD: But they're the kind of units that would have run in that market?

MR. HEDERMAN: That could be in the baseload really.

CHAIRMAN WOOD: Keep us in the loop.

COMMISSIONER BROWNELL: I just have a couple of questions, Bill. When you say you're monitoring seams issues, are we making any attempt to assign costs to those seams issues so we can determine at least approximately kind of what money is being left on the table by customers because we're not dealing with them?

MR. HEDERMAN: We're at the very earliest stage in this, but our intent will be to put quantitative estimates on everything that we can. Because we understand that just saying there's a problem is not going to be particularly helpful to either you or to us in terms of figuring out priorities.

COMMISSIONER BROWNELL: I think it's a great idea actually to dispatch some folks to the California market, particularly maybe something that going forward we'd want to look at for other parts of the country.

I'd like to just ask you for a minute about the Southeast. Might you say that the lack of an RTO in the Southeast and other areas gives us a challenge because there's less transparency there and makes it more difficult for us to actually assess what is happening in that market? Is that why that and the number of complaints you've had from that part of the country, is that why you're kind of test running the 800 number in the marketing campaign there?

MR. HEDERMAN: Well, the primary driver was the complaints. There is a different challenge there in terms of understanding what is going on exactly, whether there will be a chronic problem there or not, I think again since we're just gearing up, we will know more when we're asking the questions and finding the extent to which we can get answers. But our initial take is that we will need to do more here.

We don't want to focus only on areas where we can get a lot of information, if you will. We will focus on areas where we need to have information.

COMMISSIONER BROWNELL: You mentioned access there but also transmission, so I'm assuming there's some transmission investment issues there and then there's some kind of gaps in that system. Are you taking a look at that too and measuring the impact of that?

MR. HEDERMAN: Yes. There have been some

transmission investments, and the extent to which additional investment there would affect the efficient market function is something that would be on this list.

COMMISSIONER BROWNELL: Are we getting information from the Market Monitoring Units that exist? Are we getting it quickly? Are they reporting to you as we directed some months ago, without kind of a long, involved review process within the ISO itself, or do we need more work there?

MR. HEDERMAN: We need more work there. I think we're making very good progress in terms of building working relationships. But frankly, we haven't had the bodies at our ends to be particularly receptive yet. In some cases I think the market monitor is making judgments about, well, here's a problem and I should let the Commission know about it immediately, or here's a problem that I think I can make some progress on and I'll let them know when I've got it under control.

We just need to keep working back and forth about the need to let us know about problems as soon as they're identified, because we may know something from an example in another area that we could help them apply to that.

I feel like it's a work in progress, but I would not raise it as an area that I'm concerned about. I think it's just continuing to work well and make those teams work better. We have some seams issues, if you will, there as well.

COMMISSIONER BROWNELL: I think particularly from the state commission's perspective but in terms of building confidence and credibility, I think it's important that we reinforce the message to the Market Monitoring Units. It's terrific when they want to solve their problems, but indeed your group may have a different perspective. And more importantly, we may learn something from that problem that would help us avoid it in another area.

I'd like for people not to making the calls at the regional levels about what they tell you and what they don't. I think your job is a big one, as we've said, and it's important that people communicate regularly with you.

CHAIRMAN WOOD: Linda, Bill?

(No response.)

CHAIRMAN WOOD: Thank you very much.

SECRETARY SALAS: The next item this morning is A-4, Alliance Companies and Others. We will have two panels for this item.

At the table for the first panel are Richard Bulley of Mid-America Interconnected Network, Incorporated; Tom Kraynak for the East Central Area Reliability coordination Agreement; Derek Cowbourne for the North

American Electric Reliability Council; and Mike Gent of the

North American Electric Reliability Council.

Mike McLaughlin for the Commission Staff will start with an opening statement, then the NERC representatives will make a presentation.

(Pause.)

Okay. We'll go back. Mr. McLaughlin?

MR. McLAUGHLIN: Good morning, Mr. Chairman, Commissioners. At your last Commission meeting on June 26th, representatives of each of the former Alliance Companies attended the Commission meeting and briefed you on each of their RTO selections and explained why each of their companies made the selection they did.

The Midwest ISO, PJM and National Grid also attended the meeting and participated in that discussion. During the discussion, a number of reliability and operational issues and concerns were raised in relation to the RTO choices of each of the member companies or the former Alliance Companies, and the resulting configuration of the Midwest ISO, PJM configuration.

The issues discussed included loop flows, seams, pending generator interconnect issues, to name a few.

At the conclusion of the discussion, the Commission agreed that the next step would be to ask NERC or the North American Electric Reliability Council, to make an assessment concerning the reliability issues and to report back to the Commission. NERC has now completed its preliminary assessment of those issues and is here to make its presentation.

With that as a backdrop, I will turn it over to NERC.

MR. GENT: Good morning, Mr. Chairman, Commissioners. Thank you for this opportunity this morning. After this last meeting that Mike mentioned, we got in touch with MISO and the PJM folks and asked them to submit to us two things: ONe, a list of potential issues and concerns that they believe must be addressed to assure reliable operations of their systems and other systems in the Eastern interconnections; and two, revised reliability plans that include the resolution of these issues and concerns.

I'd like to add parenthetically here that we in no way expected them to come in with a complete reliability plan. It is our normal process to deal with that through a committee structure.

On July 5th, MISO and PJM submitted to us a joint statement of those potential reliability issues along with suggestions for what might be possible solutions, and as I indicated, neither one of them are quite ready to begin submitting the revised reliability plans.

NERC then convened a special joint meeting of our

Operating and Reliability Subcommittee and our Reliability

Authority Working Group. The Reliability Authority Working Group is the new term for the former Security Coordinator Working Group that you're familiar with. They met on July 11th in Philadelphia and discussed the paper that MISO and PJM had submitted which included the issues, and they evaluated what was submitted to us.

And gentlemen, I think we can all understand that on such a short notice there was not sufficient detail provided by either MISO or PJM to evaluate the suggestions for the possible solutions, although they did have possible solutions at this meeting and before and after. I think we were subjected to some of the same reports and letters that you were.

We were told that this configuration would improve reliability. We were told that this configuration would make it more difficult to coordinate reliability. We were told that it would be less complicated than what we had today.

We were told that it would be far more complicated than necessary. We were told that the seams issues could be more easily resolved. We were told the seams issues would be more difficult to resolve. We were told engineers can solve any problem, and we were told that this is a Rube Goldberg configuration.

(Laughter.)

MR. GENT: Based on that, I ask you, is this the configuration as you would have designed it? Probably not.

Is it the configuration that I would have designed? Probably not. But it is the configuration that the participants have chosen.

We have not yet identified a significant reliability issue that would disqualify this proposed configuration. However, we have not yet seen the detailed plans that resolve the very serious, we believe, reliability issues that have been identified.

Therefore, our recommendation to you is that you condition your approval of any configuration on the participants successfully convincing the industry, through our NERC Operating Committee, that reliability is not impaired.

One point that needs clarification in the report that we submitted to you on the 15th is that we don't believe that MISO or PJM should have to file their reliability plan in one piece. We think it's not proper for them to try to put it altogether. We expect them to be filing their reliability plans as they go to implement various stages of their plans.

We are going to dispense with our normal bureaucratic process and deal with this day-to-day, moment-to-moment, as they submit their reliability plans. With this, I'd like to turn this over to Derek Cowbourne for more specifics on the details we did consider.

You may know Derek as a Vice President of Market Service of the IMO in Ontario. He's also the Chairman of our Operating Committee, and he chaired the special meeting that we held on July 11th.

MR. COWBOURNE: Good morning, Mr. Chairman and Commissioners. Regardless of the elections made by the former Alliance Companies, t here will continue to be seams issues that must be dealt with in a satisfactory manner: Congestion management, loop flow, the ongoing need to coordinate operations between MISO and PJM and with neighboring systems, and recognizing activities and constraints on third-party systems will remain a fact of life.

These are not dealing issues, and we're dealing with them now and they will not go away. Both MISO and PJM stated that they are committed to operating their systems reliably. Both committed to having in place, appropriate reliability solutions before they take each next step in implementing a change in their organizational market.

The reliability issues arising from managing multiple seams should be easier to resolve, once the MISO and PJM achieve their common market, now projected to occur sometime in 2005.

But today the principal focus, from a reliability perspective must be on the transition period between now and the full implementation of their common market.

During the transition period, the various parts of MISO and PJM may be using different congestion management procedures. Some are using a market-based procedure, and others a non-market based procedure.

The implementation timetables of MISO and PJM may help ameliorate the situation. Attachment 3 to NERC's July 15th filing sets out the approximately time table that MISO and PJM provided at the July 11th meeting.

It appears to us that Commonwealth Edison and Illinois Power's choice to join PJM will bring them into an LMP market-based system at about the same time as if they had elected to join MISO.

Regardless of the implementation timetable, reliability plans of MISO and PJM will need to address reliability issues that may arise on third-party systems. In this respect, the Eastern Interconnection would be better served because today, constraints on third-party system are too often not taken into account.

The electric industry has the technical capability to provide the solutions to allow the proposed MISO-PJM configuration to work reliably. Some of these possible solutions were discussed, in concept, at the July

11th meeting, but sufficient detail is not yet available to allow NERC to determine if the solutions will be adequate, or how complex an undertaking the necessary coordination will be.

The more complex the undertaking turns out to be, the less assurance can be provided of its effectiveness. It likely would be simpler to manage the transition if the footprints of the two organizations were not interlaced and overlapping, electrically and geographically.

Many of the identified reliability solutions will require negotiation of agreements between MISO and PJM that address both technical and commercial issues: Who has what rights to what part of the system? Who will pay how much.

Effective implementation of the preferred reliability solutions may well turn on the satisfactory resolution of a number of commercial issues. That's not to say that the reliability standards are up for negotiation. They're not.

But some preferred market-based reliability solutions will require certain commercial arrangements to be in place to make them effective. Many of the identified reliability solutions will also require agreements with third parties elsewhere in the Eastern Interconnection, whose electric systems will be in some way affected by the operations of MISO or PJM.

Once MISO and PJM have achieved a single market, the elections by the former Alliance Companies should no longer matter. Having market-to-market interfaces should make it easier to assign costs to various necessary reliability actions.

However, so long as there are differences presented by either market or non-market interfaces or by differences between two markets, MISO and PJM, as well as the other systems in the Eastern Interconnection will need to attend carefully to the management of the seams.

In conclusion, we have not yet identified a reliability issue that would disqualify the proposed configuration. However, we have not yet seen the detailed plans to resolve the reliability issues that have been identified.

Therefore, NERC recommends that if you approve the proposed MISO-PJM configuration, you condition that approval on: One, MISO's and PJM's agreement that the solutions they jointly develop for managing seams issues are feasible and effective; and, two, NERC's review and approval of each stage of the revised MISO and PJM reliability plans. Thank you. We'd be pleased to answer questions.

COMMISSIONER MASSEY: I have a clarification that I wanted to make sure that I understood, one of your sentences. It was the sentence in which you used the word, interlaced. Could you repeat that, please?

(Pause.)

MR. COWBOURNE: The more complex the undertaking turns out to be, the less assurance can be provided of its effectiveness. It likely would be simpler to manage the transition, if the footprints of the two organizations were not interlaced and not overlapping, electrically and geographically.

COMMISSIONER MASSEY: Thank you.

COMMISSIONER BREATHITT: Derek, could you also go over your very last paragraph where you talk about the need for NERC to be involved in steps along the way? When you say we have not identified dah, dah, dah --

MR. COWBOURNE: Based on the information that has been presented to us, and the discussions at the July 11th meeting, we have not -- we did not identify yet, a reliability issue that would disqualify the proposed configuration. However, we have only discussed and been presented with the issues surrounding that configuration at a conceptual level, and we need to see the details which MISO and PJM intend to provide in their reliability plans.

COMMISSIONER BREATHITT: You also say, though, that you don't recommend a static comprehensive reliability proposal all at once, whether it needs to be presented to you as the plans move along. Did I interpret that correctly?

MR. COWBOURNE: Let me try and answer it. The timetables that were presented to us by MISO and PJM were phased implementations of the different companies coming into either MISO's or PJM's marketplace.

As such, we expect and, indeed, understand that MISO and PJM will be presented phases of the reliability plans to address each phase of the incorporation of the different companies.

CHAIRMAN WOOD: When you talk about the need to bring in the plans and determine of they are feasible and effective, et cetera, what timeframe are you talking about for NERC to go through that sign-off?

MR. GENT: It virtually depends on how quickly we can collect the people that need to take a look at it. In this last case, you had your meeting, we had a meeting on the 11th. Using that as a judge, I would say that once the plans are submitted, we're going to need seven to ten days to call a meeting, and maybe another week to be able to prepare something for you.

CHAIRMAN WOOD: First of all, I think that it goes without saying that we appreciate the ability that you have to get these folks from all across the continent to work on these issues on our behalf, and we appreciate that very much.

I think, Mike or Derek, in one of your comments, you mentioned the need to condition any approval of the configuration on convincing NERC to manage that reliability. Is that the gist of it?

MR. GENT: That's what I started with and he concluded with.

CHAIRMAN WOOD: So it's the same process?

MR. GENT: Yes.

COMMISSIONER MASSEY: You're careful to use the terminology, configuration. We don't at this point see that configuration would impair reliability.

I guess my question is, is there a configuration that might actually enhance reliability? Should that be part of the goal here? Order No. 2000 speaks of that as something, going from having multiple system operators to a few, if appropriately structured with the right reliability rules.

And Order 2000 actually speaks of the scope and configuration as a potential reliability question. I guess my question for each of you, as you speak, is, is there a configuration that would actually hold the potential to increase reliability?

MR. GENT: Let me start with this, and I'll ask my colleagues to add to this, if they choose to. Going from the five or six control areas that we have now to any configuration that ends up being two security-coordinated areas -- I should have said going from five security-coordinators to two security coordinators, is bound to improve reliability.

Any configuration here is going to improve reliability. However, we don't have enough data to really take a look and to make the studies that would be required to come up with an optimal configuration.

This is on a very short leash, and we're talking, we believe, from the information we do know, we believe we're talking about an interim period of three to four years. At some point, the MISO and the PJM say that they're going to be in the same market; they will be subject to the same constraint dispatch.

This makes it a three- to four-year transition period, depending on where you believe they will be able to join forces.

COMMISSIONER BROWNELL: To me, a four-year transition period, without having some certainty, is a little scary. But if I read the report correctly -- Mike and anybody can comment on it -- what you've said is that you can do this. It's complicated, engineers ultimately can fix anything. I'm not sure about that.

(Laughter.)

COMMISSIONER BROWNELL: And you don't have sufficient information, and that's fair. But maybe you and Derek, maybe you want to comment on that. I think you both indicated that you might have made other choices in drawing the lines.

How much money are we talking about? Somebody has to pay for this complicated solution? How much more expensive might it be? I think we have an obligation to ensure that their rates are just and reasonable, and there are not unnecessary costs being layered on.

I hear a lot of discussion about the complexity of this. Is it unnecessarily complex, and, therefore, unnecessarily expensive? I don't want to put you on the spot to put out any number.

MR. GENT: We don't have the knowledge at all. I think you should ask that question of MISO and PJM.

COMMISSIONER BROWNELL: Oh, I will.

(Laughter.)

MR. GENT: In my statement, I was pretty careful to say that we haven't yet found a reason to disqualify this on a reliability basis. I'm somewhat hesitant in saying that we can make anything work. That's sort of the implication we may have given people, but we haven't found a reason that it won't work, and we're hoping, as the data comes in and the information comes in, that we won't find anything.

COMMISSIONER BROWNELL: You also said, if I'm correct, and let me paraphrase you, that had you been drawing the lines, you might have drawn them differently. Did I hear you say that?

MR. GENT: Yes.

COMMISSIONER BROWNELL: And that's due to the complexity?

MR. GENT: That's due to my 30 years of experience in dealing with these issues, which may not even be appropriate. There might be commercial issues that far outweigh the reliability issues here.

COMMISSIONER BROWNELL: I'm not sure anything outweighs reliability issues. Derek, could you say a little bit more about the complications from the interlacing? Just elaborate on that a little bit, if you could.

MR. COWBOURNE: I believe that from an operating perspective, one of the more important aspects of the proposal is the ability of the entities to truly coordinate their security assessments, their security assessments being the studies that they may carry out to show the impact of contingencies in one part of the system and the impacts on another part of the system; the impacts on the two organizations, the generation dispatch that might exist, the transactions that might be underway.

When we're talking about during the transition period, it is, to my mind, the fact that part of one RTO will impact another RTO quite significantly; that the two must be working hand-in-hand very closely to assure reliability.

We have heard from both entities that that is what they intend to do. Until we see the details of the plans that they intend to put in place, we do not have the answers.

But, to my mind, during a transition -- which are always complex, in themselves -- the simpler it is for the operators of the system to be able to forecast what might happen, to be able to monitor the actual conditions on the system, and to undertake any necessary remedial actions following events on the system, the easier that is, the more assured one can be of reliability.

COMMISSIONER MASSEY: And what makes that easier? What would make that easier?

MR. COWBOURNE: From what I know today of the proposed configurations, parts of PJM will have significant impacts on parts of the Midwest ISO. And under the present configurations, with the electrical and geographic arrangements, that may be more than if the configuration were otherwise.

We haven't assessed other configurations at this time. Regardless of the configurations there, one always has to take account of the third-party impact on the rest of the Eastern Interconnection. But if you stand back from it and take purely an operator's oversight of this, not taking into account business decisions that might lead one to make one election over another, or the timetable that is presented to us, because of different configurations, it may take longer; it may take less, but I doubt less. It may take longer to get to the end state from a purely system operator's point of view.

I'd like to see it as simple as possible. I'd like to see the procedures, the facilities for the system operators enable them to have the best oversight of everything that might go on in that total subject.

I believe that is possible. I'd need to see the extent to which it can be done and can be achieved in the timetable that's been set out.

MR. GENT: If I may add an example, one of the examples they provided us in this July 11 meeting, apparently, the systems are going to be configured in such a way that one system, for instance, that the lose a major transmission facility on a first contingency outage, they are no longer in MISO, they are now effectively connected only to PJM.

And somebody has suggested to me that there might be something in the configuration that is just the opposite, where a major transmission corridor or line may go out, and instead of being in PJM, they're now in MISO, electrically. So they are working on coordinating their operating emergency procedures so that they can get through this, but it is an added degree of complication they will have to deal with.

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MR. MILLER: Derek, if I may, you're one of those third parties. Aren't you working for the IMO?

MR. COWBOURNE: Potentially.

MR. MILLER: Under those circumstances, under what I guess I'd call the self-selection scenario, how important is it for you to get to the single market where they're running a single market dispatch, and they are coordinated to that level. Does that make your life a lot easier?

MR. COWBOURNE: I think it will make it better for all entities in the interconnection once that very large footprint is operating to the same market, to the same security constrained dispatch. It's that security constrained dispatch that gives it the reliability aspects that we are really talking about. The market gives you the mechanism by which you may do that at the most economic conditions, but it will require not only the present footprints of PJM, MISO, but also the other entities around Lake Erie before we can say Ontario is fully a piece of that.

CHAIRMAN WOOD: So walk me through how today IMO deals with the neighboring U.S. systems with the security constrained dispatch part of this.

MR. COWBOURNE: In Ontario today we have our own security constrained dispatch. We've worked with our neighbors in New York, Minnesota, Manitoba, Michigan to determine the operating limits and capabilities between us. Our dispatch takes care of those boundary conditions. Similarly, the market modeling in New York takes care of the boundary conditions as it recognizes between they and Ontario. Between Ontario and the market conditions, market mechanisms in New York, we have to learn how to handshake that carefully. Despite the best efforts in bringing into being the Ontario market on May 1st, nothing is perfect when it goes in. We know as of the last couple of days, the events and procedures we have to fine tune between Ontario and the non-market areas in Michigan, in Minnesota. It is today a simpler means to manage than it is between the market to market between Ontario and New York.

I say this in illustration of what it may be between the different parts throughout the transition timetable in the PJM and MISO proposed configurations.

CHAIRMAN WOOD: And it's more difficult to manage that seam between you all and New York because of what?

MR. COWBOURNE: Because the tools, the computer systems and all the processes, procedures, and market rules that are put in place in the two jurisdictions. They respect the two jurisdictions, so the handshake between them is not as simple as it is between certainly the two non-market where you can more or less pick up the phone and work it out, or between a market and a non-market where only one of the entities has to relate to that complex system of market rules, processes, procedures.

CHAIRMAN WOOD: So it's actually easier for you to deal today with a non-market that doesn't have any rules as opposed to a market that has different rules?

MR. COWBOURNE: Yes.

CHAIRMAN WOOD: I hate to think that would soon be an option but enjoy it while it lasts.

(Laughter.)

MR. COWBOURNE: I'm pleased that it won't be.

COMMISSIONER MASSEY: Are you saying that a single security constraint dispatch for the entire eastern interconnection would be the best for reliability if you had the software, the computer capability to do it, assume that?

MR. COWBOURNE: Yes, I believe it would be.

COMMISSIONER MASSEY: So one would be better than two, two is better than three, and three is better than four. So the fewer number of security constraint dispatches you have within an interconnection.

MR. COWBOURNE: If there were a single market with a single security constraint dispatch mechanism for the whole eastern interconnection, you wouldn't have seams. There's still the seams in the transmission system. There's still the congestion, but there's one way to manage it.

CHAIRMAN WOOD: Mr. Kraynak and Mr. Bulley, how do you all manage between the ECAR or MAIN. There's a seam to use the FERC term but there's a boundary between to NERC regions today. What kind of interchange happens, just so I understand from an engineering point of view, what kind of interchange happens on the security constraint dispatch?

MR. KRAYNAK: ECAR is really not a operating entity, it's region. We have our various rules. Most of the control is done by control areas. They're overseen by security coordinators or reliability authorities. We don't impact the daily operations. Basically, the ECAR companies operate under the NERC rules and the ECAR rules, the main companies they operate under the NERC rules and the main rules. We are both pledged to operate under the NERC rules, so there is some commonality there.

There's some other differences between the regions. They're not that major, they are relatively slight, and they don't pose any operating problems. The company makes their transactions, they make their schedules, and there's really not any problems that I see. Companies do cooperate in certain situations. Let's say there is an overload or a lack of capacity in an area and perhaps some companies have to kind of stretch it a little in order to in some manner supply that load or even change some of the limits. There are discussions between the security coordinators of the two regions. Basically they talk through the problems, figure out what has to be done to resolve them, and I guess through the last two or three years, this is not something that's done every day. It typically will happen more often when you have very hot weather or very cold weather, and the coordinators in some way work it out and come to operating procedures that make sure that we supply as much load as we can.

CHAIRMAN WOOD: Would it be ECAR or MAIN that initiates at TLR or is that down at control area level today?

MR. KRAYNAK: It's done actually, actually the control area's request that the security coordinators are actually the ones that implement the TLRs.

CHAIRMAN WOOD: That would be you?

MR. KRAYNAK: I'm not an operational entity right now within ECAR. When I say "right now," I'm going back a ways. We've been transitioning. We used to have three. Now we've had some companies move to PJM West and some others so we now actually have more than three, and it's done by those entities that are reliability authorities or security coordinators. ECAR is not an around the clock operating entity.

MR. BULLEY: MAIN is different from that in that

MAIN does provide reliability authority services for the PJM

West companies. That's not the right term. For those MAIN members. That's not correct too. That keeps changing.

(Laughter.)

MR. BULLEY: For Com Ed and Ameran, we're still providing those services as well as some other producers and a municipal entity that has not yet joined an RTO. But I would add to that, expand on what Tom Kraynak said, as far as the reliability council functions that we do. One of those is to do extended studies looking at the season ahead and several years ahead even. For those studies, we involve adjacent regions anyway, so when MAIN does a study for the summer of 2002, we don't do it on our own. We have input from all of the neighbors around us and take that into account. They participate in the studies as well, even though it isn't just a MAIN study. It takes into account the whole area.

MR. KRAYNAK: I have one other comment that kind of goes back to what you discussed earlier about complexity. I guess in my opinion, I don't believe the complexity arose out of the fact of the voluntary selection of the Alliance companies to go to either PJM or the Midwest ISO. I think the complexity is there almost no matter what organization and maybe I should say the majority of the complexity, I think the seams issues are there between those RTOs, the other RTOs, have the same seams issues. If you asked me, give me a configuration that's the absolute maximum best reliability, I couldn't draw it on paper and tell you what it is right now.

And even so, I think the fact that you have different RTOs, that's where the complexity primarily arises out of. As for the specific details of it, it's has a much smaller impact on the complexity. I will also tell you that we reviewed the liability plans of both PJM and the Midwest ISO in the past, and both of those entities have outstanding tools, good people, lots of capability, and they are both dedicated to working out the problems. Maybe they can't offer all the solutions right now. I don't really have any reliability concerns over their voluntary separation.

COMMISSIONER BROWNELL: That seems a little inconsistent with Derek and Mike's comments. One, about the interlacing perhaps adding a level of complexity and then I think saying we don't have the level of information necessary for us to make that determination, but you have enough information that would allow you to be comfortable with that?

MR. KRAYNAK: No, I don't. Everything that Derek said and Mike said those issues all have to be worked out. They have to be worked out no matter what configuration is there. They have to be worked out between those entities and I wholeheartedly agree with what Derek and Mike said. I just am saying that I've seen what the companies have, the entities have, the RTOs, and I'm confident they can work those out. That's all I'm saying.

Now, NERC still needs to review that and be satisfied that they have worked them out but they are dedicated to it, they pledged to do it.

CHAIRMAN WOOD: Let me drill a little deeper into your comment. You said it's complex whatever they chose. Just say there's 100 points for complexity. How much of those hundred points really would be attributable to a configuration issue. Admitting it's hard to do this job, what percent of the hard relates to configuration of a given electrical topography; ten percent, 50, 80?

MR. KRAYNAK: I don't think I can answer that. I don't know. It's a pretty general question without seeing specifics. Yes, in general. The more interfaces, the more complex. But to put a relative term on it, I don't know. That's very hard to do. I will say this. The fact that we're going to two RTOs instead of having the existing configuration as Derek has said earlier, that's a much more reliable configuration, it will be easier to calculate ATCs, a lot of things will be easier.

MR. KELLY: Can I follow up on that? One of the things discussed, Derek, in your meeting was something called "facilities in close electrical proximity under different RTOs." Let me tell you how I conceive of that problem and tell me if I have it right. I think of a chess board dividing it up into RTOs. You can put the left in one RTO and the right half in another, and you have a seam down the middle. Then if you have a problem say in a black square on the left half of the board, you have to call on facilities to solve it. There's a reliability authority. It will call on reactive power units or generators or open and close switches, it will do something to prop up voltages or facilities in the neighborhood and it will solve the problem. Only when you're near the center of the board, would you have to go to a facility in the other RTO to help out. So it would be infrequent that the reliability authority would have to call on an neighbor, but it would happen.

If, on the other hand, you have two RTOs, where the red squares are in one RTO and the black squares are in the other RTO, it sounds to me entirely different, where if you have a problem in a black square, you have to call on facilities in the surrounding red squares to solve it. For the reliability authority, you need some kind of protocols or extra communications equipment or things not yet defined in order to solve it. And it seems to me the probability of failing to control the reliability problem in that situation is much greater, even though you have two RTOs under two scenarios.

The proposed configuration sounds to me like you have a black square surrounded by First Energy, Kentucky Utilities, Indiana Utilities in the red squares, and where you have Commonwealth Edison and Illinois Power as black squares surrounded by red squares in Indiana and Wisconsin and Iowa and areas to the south.

Do I understand the problem correctly? Have I characterized it correctly? If not, could you enlighten me or elaborate on it, please?

MR. COWBOURNE: You have captured my thoughts much more eloquently than I was able.

COMMISSIONER BROWNELL: Good for you, Kelly.

(Laughter.)

MR. GENT: May I offer a caution though that every RTO is going to have a similar problem, but not to this degree. Virtually every control area is entwined with another control area to some degree.

CHAIRMAN WOOD: Mike, do you want to take a stab of building on that thought of what I asked Tom? What percent of the job's hardness relates to the surface area that's permeable?

MR. GENT: I've been trying to think about that. I wrote down a number here of 30 percent. Now we're talking about reliability considerations so your commercial considerations might be 500 percent and your reliability considerations a total of 100.

CHAIRMAN WOOD: We'll get them next.

COMMISSIONER MASSEY: If Kevin's right, Derek, what isn't this a problem? It may be a problem that can be managed but isn't it a problem that we should want to avoid if possible just because there are so many other issues that also need to be managed?

MR. COWBOURNE: I believe it's an issue we have to assess how it will be managed. If we find that it can be managed acceptably, we will say so. It may then well be that it is other considerations, not the reliability considerations, that lead you to the decision on which is the right footprint for the two organizations. If we find a means by which that issue will be managed are not acceptable to us, we would say that also. We do not have that information at this time.

COMMISSIONER MASSEY: It sounds to me like engineers believe that all these problems can be managed. Just tell us what the configuration is, and we'll figure out how to manage it. I guess what I'm getting at is, and you've given us bits and pieces of this, you've said single dispatch is better than two dispatches and much better than ten dispatches. So I hear that. You've said seams management is an issue under any configuration, and I hear that. I'm still stuck on this question of is there a configuration that might actually, in addition to reducing the number of seams and the number of RTOs and the number of dispatches, is there a configuration that might actually enhance reliability, not just fail to impair it.

I just keep coming back to that. Shouldn't that be what we're actually shooting for here? We have this major effort underway. Decisions are going to be made that are somewhat enduring. It's long past time to get this resolved and move forward what the shape is going to be. Shouldn't we strive for the best or can we figure out what the best is?

MR. COWBOURNE: Should you strive for the best in terms of pure reliability or should it be based on how quickly we can get to market based mechanisms to achieve that. I don't think you can just say just the reliability but that is the aspect we are trying to assess and we certainly haven't tried to assess is there a better configuration than the one that's before us today.

We have tried to answer the question of the process and the question cannot be done reliably.

MR. KELLY: Derek and Mike, the idea of probability seems to be lost here. The statistics, we know how to fly somebody from here to London, and we know how to put a man on the moon and bring him back safely; we know how to accomplish both. But I think everyone agrees that one has a greater chance of success than the other. The other has a greater chance of things going wrong. So we know how to manage reliability in a simple RTO configuration, and we may learn how to do it in a complex RTO configuration.

What about the probability of achieving reliability in the two situations?

MR. COWBOURNE: I believe that's a part of what we have set out down the path to try and determine. If I build on your analogy, then aircraft flying over the Atlantic leaves air traffic control from the U.S. or Canada, flies blind for a while, then picks up air traffic control from Europe.

When we put a man on the moon, we not only had a mission control in Houston, but there was a backup mission control with all the same monitoring capability overlooking exactly the same system, so that either/or could have made a decision and if duplicate monitoring, everybody, both my MISO and PJM, looking at all aspects of the system, is the way to move forward, each with their normal accountabilities, each able to ensure that the overall portion of the Eastern Interconnection is handled reliability, that might be one of the answers.

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MR. McLAUGHLIN: Derek, building on that example, I'm sitting here kind of getting the impression that in studying this problem, it is complex. And as Tom pointed out, if I interpreted it correctly, he believes it can be solved. And I think maybe we'll have to ask the Midwest ISO PJM, you guys aren't talking about how much money it's going to cost. Is that correct?

MR. COWBOURNE: We are not talking about how much money.

MR. McLAUGHLIN: It may have been Mike that made the statement earlier that really the endgame is to get to the joint and common market, and that's really the solution to this problem. So to get there as quickly as possible is where we should be focusing most of our attention?

MR. COWBOURNE: In a timely manner, but taking into account reliability along the way.

CHAIRMAN WOOD: To follow up on that, Derek, I don't want to walk away and misunderstand this, but I wrote down here -- and I don't want to read that it's longer to get to that end state with a more complicated configuration during the transition.

MR. COWBOURNE: I believe what I said in answer to one of the earlier questions is, we have been provided with an approximate timetable to get to the present configuration, and we did that all under one security constrained dispatch.

I said if there were a different configuration to be approved, I don't know whether that would take longer or shorter, but I wouldn't expect it to be less time. But that was a personal commentary on it.

MR. CANNON: Just to follow up on Mike's earlier question on that so I'm clear, when you all evaluate a security plan that's brought to you, it's purely to see will it work or will it not work. There's no measure of is it the best solution or efficient solution or an evaluation of alternative solutions?

MR. GENT: No. We don't consider the cost, and rarely do we consider alternative solutions. However, in the debate that goes on in the committee process, alternate solutions are often proposed, discussed and sometimes considered.

MR. COWBOURNE: And sometimes accepted.

MR. KELLY: A question for Dick Bulley. I got a printout of TLRs that occurred yesterday. They all seem to be in Wisconsin near the Illinois border or in Iowa near the Illinois border. Sort of what would be under the proposed configuration interface between PJM if the Illinois companies were in it and MISO to the north and east?

MR. BULLEY: In fact that's the situation today.

They're still in different reliability authorities.

Illinois being under the reliability authority that MAIN is currently performing services for on a temporary basis, and then the other would be MISO.

MR. KELLY: Would it help to either eliminate the TLR problems or to enhance the transmission capacities if these interfaces were internal to a single RTO as opposed to being along the border of RTOs?

MR. BULLEY: I think what Derek said earlier was, if there were one reliability authority for the whole Eastern Interconnection, it would obviously be -- am I misspeaking here? One reliability authority is better, as we said, one is better than two, two is better than three. So when you pick on a specific seam, it could be any seam, but one reliability authority is better than two.

Seams have the potential for problems, but there are going to be seams under any situation unless you have only one reliability authority in the interconnection.

MR. MILLER: I seem to recall from a vague history that MISO was going to be taking over the reliability duties of MAPP. Weren't they also taking them over from MAIN at some point?

MR. BULLEY: I can't speak to MAPP. MAIN used to provide reliability authority services for all of its members. Many of those members have joined MISO. MISO now provides reliability authority services for those members of

MAIN who have joined MISO. They are still members of the MAIN Reliability Council, but they're members of the MISO RTO and MISO provides those services for them. MAIN now only provides services for those MAIN members who did not join MISO.

MR. MILLER: Taking that line of logic a little further, building on what you were just saying, if the Illinois portion of MAIN as well as the Wisconsin portion of MAIN is underneath a single RTO, given the historic difficulties that exist, say, in that area in Wisconsin and Michigan and Illinois area, wouldn't reliability be more easily achieved because we understand it can always be achieved, but wouldn't it be more easily achieved under those circumstances than with it under one RTO?

MR. BULLEY: I'll go back to my other answer. One reliability authority is better than two. Two is better than three.

To look at a specific case like that, we'd have to do an analysis. I'd hate to make a judgment.

COMMISSIONER MASSEY: How many reliability authorities are there are in the Eastern Interconnection right now?

MR. BULLEY: Eighteen.

COMMISSIONER MASSEY: Basically this is all gravy, moving toward fewer and fewer. I would guess -- it sounds like you're all saying that. And you would all believe I suppose that seams can be managed. Tell us what they are. We'll figure out how to do it. It's just more complicated the more seams you have, but from an engineering perspective, you feel like you can figure it out.

From that I take it that there really is no configuration that would not work. Is that true? Can that possibly be true?

(Laughter.)

MR. GENT: I'd like to say my personal distaste for dynamic scheduling and dynamic dispatch comes into play here, so I believe that they have to be contiguous electrically. I would like to make that a condition. I would not, for instance, like to have MISO take on Florida Power and Light.

COMMISSIONER BREATHITT: The "they" is what, Mike? What is the "they"?

MR. GENT: I'm not sure, Commissioner Breathitt. In the context, I'm not sure what I said.

COMMISSIONER BREATHITT: You're excused.

(Laughter.)

MR. KRAYNAK: Let me say that I do not agree that any configuration -- engineers can make any configuration work. I could draw you some configurations that won't work.

But I will also say as you get down to less and less, it's more difficult to say a configuration won't work if you put in -- let's just go to an extreme to make it ridiculous -- if you put in 1,000 RTOs and none of them were contiguous and they all had stuff in between them, I don't think it would work.

There's a line from where they won't work to where they will work, and I don't know exactly where that line is. The configuration that you have before you I feel is on the side that will work.

MR. KELLY: I heard a report on your meeting, Derek, and I was asking questions of somebody who was there. And every time I raised a reliability objection, they'd say, well, the answer to that is that PJM and MISO agreed to coordinate their reliability authorities as if they were virtually a single authority. I'd say what about planning of expansion? Will they agree to do joint planning of expansion as if it were a single entity? And as I went down the list, what about congestion management? Will they agree to do that as a single system?

It seemed to me that your conclusion that there's no reliability problem when the plans are fulfilled are based on the two entities agreeing to operate in most ways as if they were a single entity. Is that a fair conclusion?

MR. GENT: That's fair. We sort of put those words in our conclusion in the report. They have to both agree among themselves and convince NERC that this is a way that will work.

MR. KELLY: In effect, they're saying they will behave like a single RTO and therefore there won't be reliability problem, and we're saying, well, if you do that, then there won't be. Is that also fair?

MR. GENT: As long as we put in the third party constraint provision.

MR. COWBOURNE: And we wish to see the details by which they intend to carry that out.

MR. KELLY: The NERC report said that some members on the Operating Reliability Subcommittee and Reliability Authority Working Group, quote, "are concerned about the success of the operating, coordination and modeling complexities the proposed organization will require." Are there dissenting views among your members as to whether this can be made to work?

MR. GENT: There were as many views as I read off in every direction. This will perhaps wane once we get more information and those same people that were skeptical, once provided the information and the questions answered, may not be skeptical.

MR. CANNON: I think it was you, Derek, had mentioned that you wouldn't expect them to necessarily address any and all of the transitional reliability issues at one time, but it could be done sort of sequentially in some way. Can you suggest to us at all sort of what the correct sequence or the correct set of worries we should have in terms of which ones should come first?

MR. COWBOURNE: My understanding of the staged approached that MISO and PJM will use to provide us with the details is based on the timetable of when they will bring the different companies fully under their wing, as it were, in terms of bringing it into their market-based mechanisms. That would be the staging that would be used.

So all the issues that are there, whether it be loop flow, whether it be joining facilities or emergency operations or whatever it might be would be addressed in each of those phases.

MR. McLAUGHLIN: Derek, did I understand you right to say by that that in a sense you will not know for sure that there will be no reliability problems for someone like Illinois Power and Commonwealth Edison for a year or two years or more?

MR. COWBOURNE: I think it's fair to say we won't know the specifics of how PJM and MISO will handle these individual facilities in relationship with Commonwealth and Illinois Power in a market mechanism. But the processes that are put in place between MISO and PJM to handle the earlier companies that are coming in from the point of view that I spoke earlier of -- consistency, simplicity -- will want to be very much the same as what will be used throughout.

This isn't going to be, we'll deal with the left hand one way and the right hand another. It'll be a question of work it out and then apply that. How will those processes be applied as each of the companies come into the market.

SECRETARY SALAS: We will now move to the participants in the second panel. They are as follows: James Torgerson for the Midwest Independent System Operator; Bill Phillips for the Midwest Independent System Operator also; Michael Kormos for PJM Interconnection; Nick Winser for National Grid, USA; Mike Gent for the North American Electric Reliability Council; Elizabeth Moler for Exelon Corporation; Kathryn Patton for Illinois Power Company; J. Craig Baker for American Electric Power Service Corporation; and David Patton for Potomac Economics.

Mr. Torgerson and Mr. Phillips from MISO, Mr. Kormos from PJM and Mr. Patton from Potomac Economics will make presentations.

(Pause.)

CHAIRMAN WOOD: All right.

MR. McLAUGHLIN: I believe the presentations, PJM will start off with the Midwest ISO and David Patton following.

MR. KORMOS: Good morning, Commissioners. Thank you for the opportunity to at least give you a little bit of PJM's views on some of the issues being discussed today.

I think you're well aware that PJM believes that it is the right choice to honor the companies' decisions as they were made. We believe many factors went into those decisions above and beyond what are being discussed today. We don't think they should be overturned unless there is substantial reason to. And quite frankly, I don't think the complexity issues that are being discussed are substantial enough. We believe they are resolvable and will be resolved.

We think the more important point right now is to try to get markets in these areas as quick as possible. We believe that is the ultimate solution. We believe that the single market design with Midwest ISO is the right answer, and we need to be moving there sooner rather than later and continuing to try to reevaluate these decisions and opening up a can of worms I'm not sure we want to open up is going to delay that process.

So we would encourage that the Commission allow us to get back to doing our work and solve the issues as presented. I think the seams issues that were discussed --

I agree with a couple of the speakers previously -- they will exist no matter where you draw this line.

These seams exist because in reality, for the first time you're going to have two very large geographic entities joined in the middle. We will meet day one in the middle. There is no way you can draw that line to allow us any kind of buffer space between us. We will have to resolve these issues no matter what. I will grant you, yes, there are maybe some configurations that would minimize loop flows more than others. I'm not sure as to what the criteria you would use and how you would weigh that against other decisions that would need to be made in drawing those lines.

I think the bottom line, we would only be unreliable if we allow it. I think we are reliable today. The chess board example. There are 64 examples in that chess board. Doing it today, coordinating it today, dealing with it today.

I don't possibly see how going into two entities for the entire chess board is going to make it more complex than today or any less reliable than today. I think if you redraw the lines, you will simply shift redrawing the lines. And again, I'm not necessarily sure that would actually provide any real benefit to PJM.

I believe the resolutions to these seams will have to be robust enough to handle whatever the configuration is. I think if we come up with solutions that only solve the seams for certain configurations, they are doomed to fail, because in particular, those flow patterns may change over the life of these RTOS. I just don't see us coming up with solutions that shouldn't be robust to handle these issues, regardless as to the magnitude or the complexity of the solution.

I also think we should realize, as mentioned before, this is an interim step. We do have a common goal with the MISO to work jointly together to resolve it. I think solving these issues will help us actually get there faster. We will be forced to cooperate. We'll be forced to work hand-in-hand, and ultimately we should move to the common market a lot faster. We'll be first to model each other's systems in greater detail. I agree that's a complexity. I don't think that's a bad complexity. It actually allows us to have more overlap and allows us to move faster to the joint market.

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I think it's also important to realize that we've come a long way, just in a few short months that we've been having these discussions.

I think that if you look, all the companies have made voluntary selections. I think that was important. I think we have ITCs being developed in both the East and West Regions. I think that was important.

We have a split-function agreed to with National Grid for both MISO and PJM, day one, PJM for day two, and we have identified areas that we need to work together on to continue to address. I think that was important.

We have documents that everybody agrees that we have acknowledged what the reliability issues are. I think everybody should have trust in the two organizations that you are putting into place, to not move forward until they are resolved.

I think it would be ridiculous to assume we wouldn't move forward if we had not resolved those issues to the satisfaction of all parties, and we should simply just don't operate that way.

We also have a list of commercial issues. Bill Phillips will mention two. We realize that the bigger issue probably is the commercial issue. We may need more help from you in that area, but it is not in the reliability issues, ultimately, I think.

In conclusion, to paraphrase a little bit of what I think I've heard from the Commission, don't let the perfect get in the way of the good. I think we are in a good spot. I think we have moved very fast and shown that we can resolve these issues.

I would look forward to a quick decision by the Commission, one way or another. Obviously, we will honor and respect your decision, whatever it may be, but I would appreciate being able to get on with the decision. I think the companies need the regulatory certainty to actually give us the money to start solving these issues.

Obviously we can't spend their money until they give us permission to spend their money.

MR. MILLER: Oh, that's the issue.

(Laughter.)

MR. KORMOS: It all comes down to the dollar, doesn't it?

COMMISSIONER BROWNELL: So you're going to be pretty coy about how much money you're going to need?

MR. KORMOS: We need to do homework. We need to do detailed worked. Right now, our hands are tied, in that we don't know what the configuration is.

Again, I would just suggest that the sooner we can resolve this, the sooner we can come back to you with harder, more concrete answers. That is our job; that's what we do well. We think that's why you created RTOs, so we hope that we would live up to those expectations.

With that, I would conclude, and we'll look forward to answering any of your questions.

MR. TORGERSON: Good afternoon. I have stated previously that this configuration isn't ideal; it's not one anyone would come up with when you're starting out looking at RTOs. We do have concerns about reliability, commercial issues, and as Dr. Patton is going to talk about, market efficiency in market monitoring.

Our engineers have said that they can make this work. You've heard that from just about everyone talking. It's a matter of time, resources, and money related to developing the initial agreements with PJM and in the ongoing operations between the two.

Under this intertwined configuration, we also believe that it will have an impact on our joint and common market, and we will be spending time working out these arrangements, as opposed to working on the joint and common market.

However, we were asked to respond to a question from the Commission -- can this work? Our operations people, Bill Phillips, who is sitting here with me, and Nick Brown from Southwest Power Pool -- and Nick will be our

Chief Operating Officer, once we merge -- he's back here, too -- and have met with PJM's operations people about these reliability and commercial issues.

Bill is going to talk about those, but one of the things I want to say is that the issues are complex. Everybody has said that if the Commission finds that the proposed configuration is acceptable, you have to realize it's possible we will not agree on everything with PJM at some point, regardless of our joint commitment and our best intent.

We work well together; we've been working well together, but you've got two entities who may not necessarily agree. Therefore, I think that if the Commission believes that this is an appropriate configuration, the Commission should stay involved in helping us through these discussions.

I'd like to turn it over to Bill.

MR. PHILLIPS: Good afternoon. We've met with PJM operations personnel on several occasions over the last few weeks. We've jointly concluded that if certain issues are properly addressed, the configuration can probably work reliably.

These issues include actions needed to maintain system reliability, and commercial issues related to compensation for actions necessary to maintain reliability.

I think it's fair to say that we disagree over the complexity of the issues, as compared to other possible seams arrangements, but we have agreed that at a minimum, these issues must be addressed in order to make possible, the reliable operation of the proposed configuration.

Our jointly-identified list of reliability issues was provided to NERC at the request of the Chairman and the Chairman of the NERC Operating Committee. And that same list was provided to you by NERC in response to questions posed to them.

I will not go into great detail, but I do wish to quickly enumerate at a high level, what we have jointly indicated must be accomplished: Because market and non-market areas will be intertwined during transition to a single market design, and because the systems will be very electrically dependent, it will be necessary to develop an agreement to address the treatment of parallel flows in both the operations and the planning of the two RTOs.

A cornerstone of that agreement will have to be an allocation of usage rights of existing flow gates for constraints in order to prevent the overload of facilities. Further, there will also have to be agreement on the allocation of responsibility and processes to be employed to unload facilities when overloads do occur.

Such processes do not exist today that would accommodate the simultaneous and equitable dependence on both TLR and LMP redispatch for congestion management.

In order to coordinate AFC calculations, there must be substantial sharing of data, common recognition of limits, and agreements on the amount of AFC that may be used for internal security constraint dispatch under market conditions.

Once such limits and allocations are defined, both RTOs must honor those limits for both internal and external flow gates, including external, third-party flow gates. The contract-tied capacity of the two RTOs must be combined to allow each RTO to have full access to unconstrained physical capabilities of the combined network.

This will be required under a single joint and common market, and it's essential during the transition period to prevent the existence of electrical islands, and/or peninsulas that can readily occur due to the intertwined nature of the proposed configuration.

MISO and PJM must jointly develop emergency procedures that overcome the boundary concerns and allow the operators to take necessary actions without undue delay. This may entail one RTO having authorization over facilities at another for certain predefined contingency and pre-contingency conditions.

MISO and PJM must address the impacts on regional reliability criteria and regional reserve sharing programs, including reaching agreement on the reciprocal treatment of TRM and CBM on flow gates or constraints.

Due to the significant electrical dependence of the systems, substantial coordination will be required for maintenance scheduling at both transmission and generation facilities. Likewise, substantial coordination will be required on the evaluation of any generator interconnections and on plans for transmission expansions and upgrades.

This will include a requirement to synchronize the queues of the two RTOs. In addition to the reliability issues presented to NERC, several commercial issues were identified and posted for comment prior to last week's joint single-market design forum in Minneapolis.

I mention these issues because, as recognized by NERC in their response to the Commission, effective implementation of the reliability solutions will turn on satisfactory resolution of a number of commercial issues. And even high-level agreement has not yet been reached on these issues.

First, the Commission has stated that rate pancaking and transaction fees for inter-RTO transactions may impact the efficient operation of markets. MISO and PJM agree that through- and out-rates that result in rate pancaking for generation in one RTO serving load in another, is an issue.

MISO and PJM have agreed that jointly-owned generating facilities should not have energy components treated differently, based on ownership or owner RTO membership.

Losses attributable to parallel flows resulting from the operation of one RTO upon another, are not currently calculated, nor is compensation provided to the impacted RTO. This is particularly troubling in the proposed configuration with its significant parallel-flow impacts.

As indicated in the list of reliability issues, coordination processes must be developed to ensure the proper coordination of transmission and generator maintenance outages. This may often require facilities in one RTO to be responsive to the needs of the other. But no mechanisms currently exist for appropriate compensation to the affected facility owners.

The industry, utilizing extensive Commission resources, has previously made attempts to resolve some of these issues and failed. I have highlighted some of these issues, not to unduly delay RTO development, but to provide the Commission with an accurate picture of the challenge ahead in implementing this proposed configuration.

Whatever the Commission determines, be assured that MISO remains totally committed to the prompt creation of RTOs and will provide the foundation for robust power markets. Thank you for your attention. I'll be happy to answer any questions you may have.

DR. PATTON: Contrary to rumor, I actually don't have a prepared statement. I'm mainly here to answer questions about an analysis that I had done, that I believe was submitted by the MISO or attached to the answer to your data request.

The analysis that we have done represents only our views and findings on this configuration. It's not necessary MISO's views, although I think they have indicated that they agree with many of the conclusions.

The reason that we had done the analysis -- my feeling was that the market efficiency issues had not been thoroughly aired in this deliberation. There has been and continues to be a lot of talk about reliability. And maybe it's just my background, but I tend to believe that it's easier to solve reliability problems than market efficiency problems.

In other words, it's easier to keep the lights on than it is to set prices that are correct. An example of that is Y-moding relief. You're not sending any signal, particularly if you are implementing TLR inside this configuration as a means try to resolve the reliability problems.

You may, in fact, solve the reliability problems using TLR to some extent, but what you all have guaranteed is that your locational prices are not correct.

So, what we looked at was essentially the degree of electrical interdependence or interaction under the configuration of the systems that would exist, given the elections of the Alliance RTO members as they currently stand. And this analysis was done at a flow gate level.

What we attempted to do was to assess what share of the generating facilities that significantly impact each of the flow gates that we looked at, are located in one RTO versus the other RTO.

We tried to select those flow gates that were a potential cause of congestion, by looking at flow gates that are the basis of TLR calls or have been identified as limiting facilities in transmission assessment studies. But the analysis -- we don't have the ability to make the analysis comprehensive.

There may be flow gates that are material, that we did not look at. There may be some that have been resolved through investment that we did look at.

What we looked at was about 70 flow gates, and less than half showed a significant degree of interaction between the two systems. But just a summary of the types of impacts we found were that on seven flow gates that would be in PJM, 40 to 90 percent of the generation that impacts those flow gates would be dispatched by MISO.

The situation is not as significant going in the other direction. We found three, or 41 percent, of the generating resources that would be dispatched by PJM that have a significant impact on MISO flow gates.

What this means is a couple of things: One is that in order for the locational prices that you're sending to these generators to be correct, you have to recognize the constraints in the other RTO's system. That's ultimately the goal under the joint and common market, although what I think a configuration like this does is raise the stakes significantly on the joint and common market, because unless all technical obstacles can be resolved to get that in place -- and I'd like to be as optimistic as everybody else -- but those details haven't all been worked out.

This is a monumental undertaking to achieve, essentially, a single security-constrained dispatch, even over the MISO-PJM areas. We've made reference to the Eastern Interconnect.

At some point, there are just economies of scale we should think about, but it is a monumental undertaking, and so I think that should be part of the assessment of how much faith do we put into that resolving all of our potential issues.

Secondly, in addition to the market efficiency issues relating to whether you're going to be setting efficient prices, I think there are strategic gaming issues that arise, that can be separated from the efficiency issues. And that is, if you have entities outside an RTO with the ability to create significant congestion in the neighboring RTO system, then it creates the potential for strategies where a participant can create an arbitrage opportunity that only it can resolve or it can take advantage of.

I likened it in my letter to the Death Star strategy that I think is an issue that has to be monitored for, no matter what configuration you put in place. But the risk associated with those sorts of strategies are much greater in a configuration with a high degree of interaction than in a configuration with a more limited amount of interaction.

Lastly, I would say that my general view is that seams issues are not the dominant issue in this market. Based on work I've done elsewhere, there are larger economic consequences to having problems in other areas than seams areas.

Seams areas, seams issues, when you have a very complex seam, can become the dominant issue, but, yes, I would tend to agree with the notion that fewer seams is always better. I think that if you have well-configured RTOs, that having more RTOs that are well configured, would be, in my mind, better than having many fewer that are not well configured. That's sort of a summary of my analysis. I'll be happy to answer questions.

CHAIRMAN WOOD: Is just having one across this whole footprint even easier than that?

DR. PATTON: I'm glad you asked that question. I think, absolutely not, because in watching how the smaller ISOs operate, there are a tremendous number of relatively local issues that you have to deal with in operating the transmission system. I think as you go to essentially one RTO that's trying to run the entire Eastern Interconnect, you're going to be forced into making simplifying assumptions to protect the reliability of facilities; that when you're operating in a smaller area, you can afford to have the operators operating at a more detailed level with that transmission system.

So, what I think you lose is some of the utilization of the system as you grow larger, which is necessitated by the fact that you're dealing with an order of magnitude more of complex issues related to the transmission system.

CHAIRMAN WOOD: I know they are your client, but do you think that the MISO's plan to create a single virtual market with PJM is wise or not?

DR. PATTON: Sure, but the way I have viewed it is that it was a structured coordination between MISO and PJM, and just to be clear, I'm not advocating any one particular configuration. I think, you know, I looked at some alternatives in the paper, but I think there are configurations where you can have a seam with relatively limited interactions, located pretty far west, and have a big chunk of what's now in MISO and PJM, and that would work.

So let me give you an example of what I mean by structured interaction: If there were real-time interactions between the market models running in PJM and running in MISO, that would exchange constraint information, so you get essentially some redispatch in each of those areas to manage constraints in those areas.

That's certainly a very good thing. The need to do that extremely well goes way up when you have a high degree of interaction between the two to the point where you might feel like you have to collapse the thing into a single computer running the dispatch, in which case then you have issues you have to think about, related to are you going to have two sets of operator but one computer running the dispatch. The things the operators do are going to interact with the outcomes of the market model.

CHAIRMAN WOOD: Actually you know, it's funny, because I walked in here with one opinion about things and what I'm hearing from actually the four of you all is being forced to coordinate all this complicated stuff on the front end may actually get me to that common market faster than your time line. But what I want to know is, and it was raised, David, in your paper, is once you get to the joint and comment market, are there lingering things about this configuration that continue to just make it economically inefficient beyond 0405.

DR. PATTON: I think the only issues with the joint and common market are what confidence do we have today that we know exactly what that's going to look like and that it's feasible, and do we have any information on potential inefficiencies that may be generated by trying to operate an area that large. And so I think certainly I should be willing to do this since I'm an economist. If you were willing to assume that this was all feasible, it should be an engineer the same as if they are feasibility issues.

(Laughter.)

DR. PATTON: But if you're willing to assume that this was feasible and you could operate at the same level of detail and get the same utilization out of the transmission facilities with a single dispatch over the MISO PJM area, I think certainly this issue disappears because in effect you have what looks like a single RTO at that point, so you've sort of defined away the potential problem.

CHAIRMAN WOOD: Ms. Patton and Ms. Moler, remind me again from two weeks ago if you all are going to be integrated. It at least looks like from the NERC attachment number three to 04 anyway. What was the attraction of going with PJM. Was it that extra year of getting into the market before going with 05 for MISO.

MS. PATTON: I think the data in the NERC report is a new date. Since we were here several weeks ago, our discussions with PJM yesterday, they still really don't have that date nailed down. We are still hopeful that it still actually will be in 03, when they get us integrated in --

MR. KORMOS: Just so we're clear, the '04 date we have shown at the NERC meeting was the latest date we thought we'd bring in the companies. And Kathy's right. We haven't nailed that date down.

CHAIRMAN WOOD: If you all can do it in '03 and '04, why can't MISO do it in '03 and '04? Aren't you all using a lot of the same rules and structures and stuff anyway, Jim?

MR. TORGERSON: Our plan is to have the Midwest market up by the end of '03.

CHAIRMAN WOOD: LNP and all that?

MR. TORGERSON: LNP, FTRs, day ahead market, real time market.

CHAIRMAN WOOD: So it's just the integration issue that remains to be done at the back end of your transition.

MR. TORGERSON: With PJM?

CHAIRMAN WOOD: To the single. You all will have mirror image markets but they won't be consolidated.

MR. TORGERSON: They won't be integrated at that point. What we'll do after '03 is start working on we call them the "enhanced market portal" which will allow customers to go into both at one interface, and then -- and I've had discussions with Phil Harris -- how far do we go the next step. We've got to do a cost/benefit analysis. Do we then combine everything into one system? That's what we've been talking about doing but if we do it with two and have an interface between customers, which is seamless to them, does that make more sense? Is it more cost effective? We haven't done that cost/benefit yet. That is what we'd take to '05.

CHAIRMAN WOOD: That's helpful. That wasn't clear to me before. Folks?

COMMISSIONER BROWNELL: I'm still not clear on the timing issue. Timing was driving the decisions of the companies. You're not really sure about the date. You hope

'03 but it might be '04. Would the same integration date hold true if they were in MISO?

MR. TORGERSON: Commissioner, our belief is if they were in MISO, we would still be able to hit '03 because we're going to have model that part of the system anyway and it'll have to be part of our model and part of everything we're doing. We can't ignore the Illinois area. So yes, our plans right now say we'll have this up and running by the end of '03.

CHAIRMAN WOOD: Have you all had any discussions about collapsing this rate issue that we've been kicking around? Or is that just waiting for us to kick?

(Laughter.)

MR. TORGERSON: If you mean between us and PJM, we have not entered into any discussions. We've raised it with PJM and said, you know, this is an issue for us. And they said, yes, we understand. We have no entered any discussions about it.

CHAIRMAN WOOD: Your plate is as full as ours, huh?

MR. MILLER: I wanted to start with one question from Mike. I think it's fair to say that by any measure, the seams that we have, I know for example, Ms. Moler often refers to well seams are going to exist regardless. That's certainly true. But the seams that are created by the self-selection scenario is more complex than anything that we've seen thus far. And thinking the way I think of things that commercial reliability issues are kind of interrelated, I don't think of them as one or the other because you can't solve one without affecting the other. So going to the seams that we've dealt with thus far which exist in the Northeast, which I think are considerably simpler by any measure, how difficult are those things to iron out? Again, I'm not talking about merely from a reliability issue because as my memory serves there is a 1998 MOU between the three ISOs in the Northeast about ironing out things.

I don't think we are there yet. In the seam that exists, for example, between New York and PJM, is a seam that exists between two models that are essentially on the same market platform.

MR. KORMOS: I'll try to answer. I think there are multiple parts. I'll try to get them as best I can. I think you're right. Draw a straight line right across New York and Pennsylvania and you still have a major seam. It is a seam when you butt two markets up. I actually think we have done a great deal. We have actual agreements with New York called the "Continuing Usage Agreement" filed at FERC which allows each of us to pay for loop flows congestion on the other system. We have agreements as to how to measure those and what's called the 5018 line branch. A lot of the reason we do that is that we have a clear, visible price.

There's a lot more certainty. The one thing to realize is why these seams are more complex as we put markets in there and are clear transparent market singles.

The commercial aspect I do believe will become easier to resolve. Right now, there is no transparency in this area of the country. It makes it much more difficult. I understand it's more complex because there may be more loop flows. I don't think there's anyplace you can draw the line between PJM and MISO that's going to remove it. New York/PJM is as good a line as you probably could have drawn there, and that still has seams and they are still of a nature we have to resolve them; we can't ignore them.

If you could draw a configuration that could allow us to run, that would be okay; we can't. They may be more complex in that there may be more loop flows. I haven't seen David's study but I trusts his judgment if he's saying that. But to me, the solution should be robust and vigorous enough to handle whether it's more or less loop flows. That's still all we're talking about is loop flows.

MR. MILLER: Let me ask a question that goes to the use of LMP because both systems are going to be using the LMP congestion management system. Under the self-selection approach, the Midwest ISO, as I understand it, and I'm using topography as opposed to geography, it seems as if there are going to be significant what I'll term LMP

Islands. If I have understood LMP commercially, and both LMP in terms of the economic effect, LMP in terms of using it as a tool for congestion management for showing where the highest value of power is, to show you where the problems are is best used when the LMP numbers can relate to each other.

David, under a configuration -- and I'm saying, you know, before the single market, before we hit the single market -- are the LMP numbers that could exist in the Midwest ISO under the self-selection approach? Would they have any economic meaning?

DR. PATTON: Yes, they would, but only in a limited sense. As an example, if no constraint is binding on the MISO system, but you have a constraint that is caused in Illinois or in some portion of PJM, by that generation, unless those LMPs are recognizing that constraint, you're not going to be sending the economic signal associated with that constraint. So what would generally happen is you would get a TLR so you're not really relying on location pricing to resolve your congestion, and it undermines some significantly the predicates for why LMP is good in the first place.

On the flip side, what would happen if exactly the opposite were happening, that is generation outside the

RTO is causing congestion, you would get more expensive attempts to redispatch by the generators in the RTO because you don't have access to the generation outside the RTO. You'd get prices that would potentially overemphasize the constraint plus the flow that is being caused on that constraint by generation outside would be paid by your RTO in the form of uplift which is difficult to hedge without some form of agreement to build that back to the other RTO.

It sort of creates a number of problems. I have to imagine that we would have to do something immediately at the time that the LMP was going in place if we're not to the joint common market that would resolve some of these economic issues.

MR. KELLY: Question for I think Bill Phillips though others are welcome to comment. I don't understand clearly how much of the effort that you describe, Bill and others described, is solely to manage the interim and not need it when you get to the joint and common market, and how much of the effort is needed for the joint and common market. In other words, if it were for 80/20, the 80 percent effort, if it's very costly and it's only to get you through a short time, why not delay integration and work on SMD like everybody else around the country to get to an SMD common market later, whereas if a large fraction of the effort is not only to get through the interim, is not only useful to get through the joint and common market. I don't have a good sense of how much of the effort is for the interim, and for the eventual.

MR. PHILLIPS: I don't know if the numbers are 80/20 or 70/30 or 90/10, but I do believe the preponderance of the effort is up front in the early stages because the greatest complexity, I believe, is in trying to marry an intertwined area both market and non-market activities, given that one is dependent on PLR for congestion management and the other is dependent upon the single market dispatch for congestion management.

MR. KELLY: Bill, if I could interject. In the single common market, both will use LMP so if there were a lot of moneys expended to manage the fact that one is TLR and one is LMP, would that be wasted.

MR. PHILLIPS: Will there be some throwaway work? Yes, there'll probably be some throwaway work. Although even when we get to a single common market, we still have to have processes that effectively deal with third parties who are not yet in a single common market that may still be in a TLR regime. Will it be entirely thrown away? I don't believe so.

The other response I would give you is as an operator. I can't ignore the issues until we get to the single common market. They are issues. They do impact reliability, even if it is throwaway work in getting there.

I don't know how to avoid it. If you proceed on this path, these are issues that must be addressed in order to maintain the reliability during the transition period.

MR. KELLY: But we're trying to decide whether to proceed on this path, so if proceeding on that path were delayed so that somehow we went to the common market as the first step, I was trying to figure out how much money is saved. Reading between the lines, you're saying not much, but I'm not real sure that's what you're saying.

MR. PHILLIPS: There are different issues at different stages in our mind. There are issues that exist when you have the non-market-to-market. There'll be different issues when you have market-to-market but they're not identical. There'll be other issues that exist even when you get to a single common market because the single common market, for example, in and of itself, does not address singular rates. The rates may not be identical even under a single common market and if there are not, there are still issues.

MR. KELLY: Anybody else? Is there a lot of money spent that wouldn't be needed? Is this only needed for the interim?

MR. KORMOS: To build on Bill's point, we've had this discussion. If we were to find that to be true and if delaying one of our implementations to allow the other to catch up is the right thing to do on a cost/benefit-wise, that will be what we propose. I don't see a lot of throwaway. I think the overlapping models, the communications procedures that we need to put in place are there for the long term and will always be there for the long term.

The negotiation of the commercial issues, that's probably thrown away. I'm not sure of any way around that, and I'm not sure that's a big, significant cost anyway. It will be us meeting in a large room and hammering out the issues till we resolve it.

MR. KELLY: Will it be a distraction from standard market design implementation?

MR. KORMOS: I'll tell you July 31st, when I see the standard market design implementation how much work I actually have to do. That is a fair question. You're absolutely right. We will have to look at that to see how that alters our plans.

COMMISSIONER BREATHITT: In the meantime, your companies have stated you're not spending any more money on moving forward. Is that correct? Or just you said that?

MS. PATTON: Just Illinois Power said that.

MS. MOLER: If I could respond to that, we have an interim company that we set up thinking that we're going to be an Alliance RTO. That company is funded through the end of the month. It has the rights to the software and hardware that will make all of this work across the Midwest, and we need some certainty, as I said three weeks ago, before going ahead, since we last met, we have made substantial progress. I'm not sure what the proper time in this discussion to report on this progress. I don't want to interrupt the discussion of the market design and reliability issues because they're very important, and I think maybe Mr. Wincer can comment on this, or I'll be happy to go ahead, whatever is the Commission's pleasure.

Since last meeting, AEP, Com Ed and Dayton have come to an agreement with National Grid on forming and independent transmission company to operate under PJM, we're ready to go forward with that.

CHAIRMAN WOOD: Isn't that in advance of the 30 days?

MS. MOLER: Yes, we did. We heard your frustration with the loopholes in our prior MOU, so we got to work because IP -- and I don't want to put words in Kathy's mouth -- but I think they stated very carefully they're not willing to spend additional resources at this point. But the other three companies have agreed to go ahead with National Grid and form the ITC under PJM. We're prepared to go ahead with that and do the work. We're spending money today on lawyers, we're spending tomorrow on lawyers. I expect we'll be spending money next week on lawyers. We are really ready and anxious to go ahead. We believe as our respective response to the data requests showed, that there are good and sound reasons for the decisions we've made. We documented those extensively in response to Mr. McLaughlin's data request. Ours was dated July 10th, and Exelon Corporation has more retail customers than any other utility in the country through Com Ed and PECO. Both Com Ed and PECO have capped rates for the foreseeable future. We have a commitment both to the federal regulators and to the state regulators and to our customers to operate reliably.

We believe that having both companies in a single RTO will enhance reliability and will make our operation much more efficient, which when Commissioner Brownell asks about how much all of this will cost, that's really important because we have capped rates. We think this will save us money, it will make us more reliable rather than less. It will also dramatically lessen our external loop flows if both companies are in PJM rather than one in MISO and one in PJM.

In response to Mr. Kelly's earlier comment about the chess board, I think you need to think of AEP and Com Ed as a single, very large black square, not two different black squares. The companies are electrically contiguous if you look at the documentation we sent in in response to the data request, that you can see that.

Some of our folks have said internally that we're Siamese twins and really shouldn't be separated, but we really have a desire to go ahead. We're prepared to go ahead on a voluntary basis.

We think that ultimately this will enhance reliability and efficiency, and I had to get that off my chest.

(Laughter.)

MR. MILLER: In following that up, Ms. Moler, one of the things that I know that you're strongly connected to AEP, that's certainly true. But in looking at your connections elsewhere and the Illinois' companies connections elsewhere, it seems that the connections are even stronger to the rest of the Midwest ISO.

Your connection to places like Wisconsin and to Michigan and to other places are pretty strong, too, aren't they?

MS. MOLER: They are pretty strong, but they are overwhelmingly stronger if you look at the numbers, both the electrical interconnections and the actual flows from Com Ed to AEP and Com Ed to IP than they are anyplace else. I can say that categorically.

MR. McLAUGHLIN: Betsy, the Midwest ISO filed and pointed out in one of its filings that the tie line capacity between the markets, maybe I assume you've seen that from

Jim Torgerson, it identified that the capacity between AEP and Commonwealth Edison and Illinois Power is approximately 7,000 megawatts.

The tie line capacity between the Midwest ISO companies and Commonwealth Edison and Illinois Power is approximately 40,000 megawatts. It seems like it's almost six to one. Are you looking at it just from the one tie between AEP and Com Ed is the largest single tie you have? Can you explain that for me?

MS. MOLER: I hope that the response to your data request might adequately answer that. It shows from our point of view it defines more carefully I think that Mr. Torgerson's Bismarck presentation did, how we measure things consistent with the NERC methodology and ratings that are specified.

It shows that we have far stronger ties with AEP and with Illinois Power. We frankly do not understand some of the numbers that are included in Mr. Torgerson's presentation. But we believe that the information in the data response clearly documents the strength of the Com Ed interties to AEP and IP. We can go into these in whatever technical detail you wish to do so.

Steve Nauman, who is much more conversant with this than I am, can do so. But our summer ratings with AEP are substantially higher than anyplace else on the system and with IP as well. The actual transactions, the natural markets, as the Commission has termed them, are also substantially higher with those companies than anyplace else.

MR. McLAUGHLIN: Just one follow-up question. Does Commonwealth Edison have any problems going forward without Illinois Power?

MS. MOLER: As I understand it, Illinois Power has committed to be in PJM. There's no question that they will go to PJM. They're just not at this point part of the ITC. So the answer is no.

MR. MILLER: Kathryn, let me ask you a question. You stated earlier that part of the decision that IP made with regard to its selection was based on capacity availability, and that for example, Ameren, there's just no capacity available.

I know how that cuts both ways. One way you could say is that you're not able to do any new business nor go in that direction. That could also indicate that you're also heavily connected. You're doing an awful lot of business together.

MS. PATTON: We don't really do that much business with Ameren yet. As you can see by our import and export numbers, compared to Com Ed and AEP, the Ameren flows just are not significant really from us serving our native load or for exports for generators off of our system. There's just not a lot of business there.

My suspicion is -- and I'm not the technical person here -- but from what I hear talking to some of the commercial types, a lot of the capacity to Ameren is already owned by others, like AEP had bought a big chunk to get down south and others. So there's just not capacity available there.

And my concern about IP being left behind and MISO and Com Ed and AEP going to PJM is, we've become almost stranded at this point because we have to rely on going through Ameren to get anywhere into MISO with any significant ties, and there's not any capacity available, because it's already sold out to third parties. We're not going to be able to get imports or exports in without having to pay huge export fees that occur sometimes at the borderlines of RTOs.

MR. MILLER: I certainly appreciate that. But under the configuration that's been suggested here, there seem to be significant areas of the map that are stranded, too, like the Wisconsin area. One of the concerns I think that some people have raised to the Commission, I understand that you'd be stranded but that others would be stranded as well, too.

MS. PATTON: I really can't speak to the other systems. I'm not the technical engineer. One thing I did want to clarify on the IP's decision not to join the ITC at this point, I think as I had commented a couple of weeks ago at the meeting here, we're at the point now where we're not willing to spend any more money toward joining an RTO until FERC makes a decision.

The ITC agreement as drafted requires us to continue to spend money. With a FERC decision imminent hopefully, maybe today, a couple of weeks, that decision will be made at FERC. Then we can make the decision as to whether joining the ITC is appropriate for us.

We are absolutely committed to joining PJM and will seek to start negotiating with PJM as soon as the 30-day timeline is up. We committed in the original MOU not to do anything inconsistent with an ITC prior to the 30-day passing that I believe occurs on the 21st of this month. We've already contacted PJM to start discussions after that deadline passes so that we're not in breach of our contract there.

COMMISSIONER BREATHITT: Start discussions with PJM?

MS. PATTON: To join it with the individual transmission owners.

COMMISSIONER BREATHITT: I'm confused. To join as a transmission owner. You're committed to joining PJM, but you haven't signed anything yet?

MS. PATTON: We signed an MOU that committed us to join PJM either as part of the ITC or as an individual transmission owner. That MOU said for 30 days you can't do anything inconsistent with being an ITC. But after that 30 days passes, you have to -- I forget what the deadline was. You have five days to work toward joining PJM.

I wanted to make clear that whether or not we join the ITC, we are absolutely committed to joining PJM.

COMMISSIONER BREATHITT: That was the clarification I was looking for. Craig?

MR. BAKER: Commissioner, I'd just like to add to what Kathy said. I think she'll concur with this. We have not been sitting waiting for the 30 days or the creation of the ITC. We're all excited about the ITC and we would hope that Illinois Power can find a way to be part of it.

But we've been continually, all of the companies who have chosen to go to PJM, to meet with PJM dealing with implementation, dealing with the issues that need to be resolved, whether the companies go as a TO or an ITC, those things surround operating reserves, rate design, allocation of FTRs -- all the things that we need to work through as we integrate these companies into PJM regardless of the model that they go in -- that work has been ongoing and continues today. I'm sure we have people meeting. There have been kind of nonstop meetings. We have working groups, and that is making significant progress.

COMMISSIONER BREATHITT: Nick, for you to administer, though, your expertise, you need to do that with the ITC type arrangement. Is that correct?

MR. WINSER: Yes, that's correct. You can't really have agreements with AEP, Com Ed and Dayton on the east. It's very encouraging to us, as I've spent too much air time here saying, we've had real discussions about seams. But in truth, it's going to come down to how robust and how vigorously managed the transmission system is. That's what's going to determine how well the benefits that can come from wholesale markets will flow through to customers and how quickly. That's an exciting prospect for us to have effectively six companies and admittedly two different ITCs where we can try to build that model, try to bring active management to the grids, increase the vigor in terms of investment.

That's I think what it's going to come down to I think as we go through SMD and get there in terms of the market arrangements, we're going to see the factor being increasingly the capability of the transmission system and the formation at least of two ITCs gives me great encouragement in terms of we can start to revolutionize that sector.

COMMISSIONER BROWNELL: Nick, do those two ITCs look the same? Same function organization, same structure?

MR. WINSER: They're not identical as laid out currently. We have been exploring with PJM some differences that occur between the two.

The MISO model very much lines up with the Alliance and TransLink rulings. We've sort of been in daily discussion with PJM on this, and where we started off that discussion effectively, what we would have had is an ITC with the same responsibilities and opportunities as a vertically integrated TO.

Within the last couple of weeks in recent days, we've had extremely constructive discussions, as Mike says, with PJM, on trying to explore where an ITC should have greater opportunities and obligations within PJM that a vertically integrated TO, giving us a great opportunity. PJM thinks it's a great opportunity to enhance the operational planning, and planning sort of responsibilities that an ITC could have so we can really bring maximum value after the ITC model.

Those discussions are ongoing. They're going well.

COMMISSIONER BROWNELL: Just so I'm clear. So there's an agreement that has been signed with these companies to form an ITC, but that agreement is not the same agreement that exists with the companies in MISO, but that agreement is a work in progress?

MR. WINSER: Yes. The agreement actually had what was called a day two allocation of responsibilities which very much lined up with what a vertically integrated TO could do and actually did give us some freedom to start to create value for customers out of the transmission system.

The agreement also had language which said that as FERC's policy on developing the hybrid model ITCs went forward, that we would try to develop alongside that as your policy allowed ITCs to get greater functionality, that could be recognized. We sort of got ahead of that game a bit in recent discussions, and we are exploring with PJM currently our ability to if you like adjust the day to arrangements. Perhaps Mike could comment and make sure I've got this right -- adjust the day to arrangements so we can bring absolute maximum value out of the ITC model under PJM.

I think there's an evolutionary sort of aspect to this.

COMMISSIONER BROWNELL: Correct me if I'm wrong, Mike. I think Phil has said publicly he endorses kind of what was outlined in the Alliance order, so he's perfectly content with that?

MR. KORMOS: The Alliance orders didn't really talk about a day two. It talked about, yes, when we come with a market design, we'll have to add it.

What we did in the MOU was try to at least define what we knew about the pro-PJM model with our markets in place, what we've seen in the SMD whitepaper and then base that split on those factors. So we did agree to a day two.

We and the MISO at this point haven't agreed to a day two. That was one of the big differences. I think our day ones are very close. We did try to agree to a day two. We felt that was important, at least based on what we know now, we put the caveats in there. And as Nick is saying, there is an issue that there is no special category in PJM for an ITC today. It's only because they don't exist today.

We have absolutely agreed to work with them, look for opportunities. I think we're in agreement on things like economic expansion, something FERC gave us that we did not ask for. We would love to see the ITC pick up some of that. It would take a burden off of us. The commitment there is to work with them. We need to work with the other participants. We can't do it in a vacuum and they understand that, and we're going to drive forward and hopefully further define really what their business model is, what other responsibility they really need and want, and then how we go about making sure it still holds all together in a model where there's ITCs or non-ITCs.

COMMISSIONER BROWNELL: And the timeline. It seems to me that getting the details of what this ITC is or is not does or does not is critical to this whole integration issue.

MR. KORMOS: I'll put words in the grid's mouth, because they've told them in meetings to me they believe they can be viable with the current split. It's not idea for them.

I think they're comfortable going forward. They would like to do it, so I'm not sure if having the details today, next week or next month is that critical. We both have a lot of work to do to get ready for day one, and I think we're all throwing our resources there. I think they would like to move as soon as possible, and we would like to honor that request.

Most of us are waiting for SMD to see what happens in SMD as well. So that will drive that timetable.

COMMISSIONER BROWNELL: So you have no target date in mind but SMD, we issue it, you love it, there aren't any comments?

(Laughter.)

COMMISSIONER BROWNELL: We move forward.

MR. KORMOS: In a perfect day, that's the way it would work.

COMMISSIONER BROWNELL: Target dates discipline all of us. When would you expect to be working all these details?

MR. KORMOS: We've already started the discussion. I would assume that we will get very serous about them after day one, which is the end of this year, and have them in 2003 agree to it. Unfortunately, for the next four or five months, we're both going to be very busy trying to get the day one implementation, assuming we get the green light to go. But I think it's very doable in 2003.

COMMISSIONER BROWNELL: First quarter?

MR. KORMOS: A lot of it will depend on what they're asking for and what our other stakeholders are going to lay on them.

COMMISSIONER BROWNELL: I'm really trying to get comfortable with this because there's a lot of confusion out there about PJM.

MR. KORMOS: We know the areas they are interested in. We definitely have agreement that those areas are the right areas. They're the areas we'd want them to be looking at. We're in total agreement there. We haven't sat down and really defined exactly how they will differ then from the other TOs and how that all still holds together to the comfort of everybody -- the generators, the loads in the PJM region.

COMMISSIONER BROWNELL: Okay.

MR. WINSER: Can I just chip in? In the meantime, I believe that SMD will bring a lot of these issues to the fore, or as we go into the detail of the structures that will soon site SMD. Our agreement does give us the opportunity to adjust the relationship. As we go forward, SMD is going to be on the table by then.

As you know, I'll be fighting very hard to get what I believe is the proper role for transmission companies in the SMD arrangements, and I think PJM is very happy to reflect that as we go forward.

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DR. PATTON: I hate to interrupt. I have a prior commitment that I can't reschedule, and I will have to excuse myself.

CHAIRMAN WOOD: Do we have any wrap-up here?

MR. KELLY: Mr. Baker may enjoy being ignored, but there's a question that's probably --

(Laughter.)

MR. KELLY: It's better directed at First Energy, but there was data in your submission that showed that the interconnection strength between First Energy and AEP and PJM combined, was approximately 20,000 megawatts. Betsy Moler described AEP and CE are siamese twins with the interconnection of just 6,000 megawatts.

The interconnection of First Energy with the rest of MISO appears to be a fairly weak one, where the Michigan company, which isn't terribly well connected with the rest of MISO. Is there a sense in First Energy, being in MISO, if AEP is in PJM -- I probably should have Jim chime in on that, too -- and I know it's a better question for First Energy than you, but it's your dataset that prompted the question.

MR. BAKER: Let me answer a couple of the questions. I'm going to pass on the question of why First Energy made the decision that they did. That's clearly for them to articulate.

We do have a significant interconnection tie with First Energy. It is on the order of 11,000 megawatts. The business we have historically done has been more with Commonwealth, back and forth, than it ever has with First Energy.

There is a significant tie as well between First Energy and the Michigan companies. It is not a small tie.

I'm not sure exactly how many ties, but the numbers that I have seen in front of me indicate that that's to about a 4,000-megawatt level. Now, you are correct that the tie between -- that other parts of MISO and Michigan is a smaller tie, but there are significant ties in that area.

But why the decision were made, I'm not sure.

MR. KELLY: What I'm going to -- and I'd like to have Jim comment -- is, if FERC approved the proposed configurations, does anyone really believe that's stable, or if we're going to go through a series of sort of domino effects of eventually AEP went with PJM, therefore, Commonwealth went with PJM, therefore Tipega has to go with PJM?

Are there other therefore's to follow in First Energy, Michigan, Indiana, being between Illinois and Ohio, and would there be effects that would even draw in some of the plains states, which are part of a great big -- as I think of the Midwestern hub, centered around Illinois?

MR. BAKER: I would doubt that there would be a next step. If the Commission were today to tell everyone that their decisions are accepted, go forth and get it done, all the work over the next couple of years will be integrating, first into a day one environment; second, into a day two environment, and that's where the efforts would be.

I don't think it would be a switch to make new choices.

MR. KELLY: Jim, any comments?

MR. TORGERSON: As far as First Energy, Craig characterized it well. There is a very strong tie to Michigan. I think, if my memory serves me right, there are three, 345-KV lines that they have into Michigan, and their transfer capability, I'm not sure exactly what it is, but it's 4-6,000. I don't know the exact number, but I know it's fairly strong. I think when Stan Szwed was here for the meeting three weeks ago, he highlighted how much internal generation they had, versus what their internal load is. So they do not export a lot out, which was the other point.

So, they have very strong ties with AEP, but they also do with Michigan, and then Michigan has a weak tie in the NPSCO. That's how this whole ITC thing that's being formed will become functional.

As far as the other question, would we see people moving? That's a risk, I think. I don't have anyone saying that they would. I know of some companies that are concerned about the through- and out-rate we have. We've been discounting that to make sure we equalize the opportunities for people to do business in different areas, but we still have a through- and out-rate and people that are in PJM wouldn't, unless you discount it to zero.

There's going to be a difference, so I think it's a risk. I don't know how big a risk. No one has indicated that to me at all.

The other thing I don't think ever did get answered was the question regarding how much is this going to cost, to have two different entities. We did some preliminary looks at it, and we feel we're probably going to need an additional somewhere between 10 and 20 people to work things out, and we'll probably have to put people in PJM's control room. They would have people and hours just to make sure.

We're working jointly. The initial costs, we haven't really put a pencil to that. We will have to have the models put together anyway, so I don't know that there would be an incremental capital cost.

The communication links we're going to have with

PJM, we'd probably be spending money earlier than we would otherwise, and we'd still have to have the communication links to PJM; we just have to do it earlier on. But I'm guessing that you're probably looking at a couple of million dollars a year of incremental costs, just to deal with this configuration. That's just our guess right now.

MR. KELLY: One last question, if I could, for Mike.

MR. CANNON: Just to have one followup on that, does PJM have an estimate of cost?

MR. KORMOS: Ours would not be as high. This is, again -- we've been honest about our disagreement as to the complexity. I don't think we're looking at anywhere close to 20 people.

I think, again, that will be the driving factor. I don't think it's hardware or software kinds of expenses. The communication, the modeling, all has to be done no matter what. I think it would be significantly less.

A 20-percent increase in my division -- a 20-people increase would be 20 percent, and I just don't see it being that high, just to resolve these complexities. We deal with these things every day.

Again, I think it's a couple of people. I don't think it's anywhere close. But we'll work that out.

As I say, we need to sit down and do the analysis and decide, really, what is the solution, and what is going to be the automated solutions? We're comfortable that it's not a terrific expense compared to all the other decisions that are being made regarding Exelon, as one example. We don't think the additional expense to the ISOs are that significant.

COMMISSIONER BROWNELL: And that's the case? Whatever the configuration, the costs are the same?

MR. KORMOS: All these things, I think we will have to do, no matter what. It may be, incrementally, we have to track a couple of more flow gates than we would have with a different one.

I don't think it's anywhere as dramatic as a couple of million dollars. Maybe Jim's couple of million dollars is total. To clarify, even if you redraw it, it's still a couple of million dollars, maybe a couple of hundred thousand less.

MR. BAKER: I would comment that I would agree with Mike on where his estimates are. When I think of AEP today, we have a pretty irregular seam, I think, where we're connected with over 20 companies at 140 interconnection points and a lot of transmission goes through us. There's a lot of service.

It doesn't take those kinds of numbers for us to manage that in the environment where we're the transmission provider today.

MR. KELLY: The final question for me, anyway, is for Mike and Jim. I was looking at the Order 2000 RTO functions. There are eight of them. And as I understood it, for all but one of them, it sounded like you were going to perform them as if you were a single RTO.

There's a single congestion management system, a single joint transmission planning and expansion. You'll have to coordinate with third parties jointly to take into account loop flows, and as you march through the various RTO functions, seven of the eight you were doing jointly. The one missing one would be a common tariff.

That leads to two questions. One is, is there any thought of making it eight out of eight? And the other is, would it almost be fair to characterize this agreement, if it works out as planned, as a sort of a virtual single RTO with a kind of bicameral governance?

MR. KORMOS: I would actually tell you I think it is eight out of eight. I think we do have to have a common tariff. Our market, the way we've developed it -- now SMD may be different than what PJM currently does -- requires that there is a single rate internally.

We use license plate zonal, but there is no internal transmission service that is going to by default going to say that we have to resolve the tariff issues between ourselves. I think that's the bulk of it is the rate.

I think we are absolutely going to be virtual in the middle. There still may be a lot of reasons why at either of our ends, I'm not sure how much I need to be involved in his western border. I'm not sure how much MISO wants to be involved in my northern border. I think we will be two in the middle. We will have to absolutely operate as one. I think that's the vision.

How far we go with that, Jim's point is excellent. I mean, we need to sit down and decide where we've gotten the greatest benefit, cost benefit-wise, as to maybe there is one RTO. Five years from now, maybe that is the right decisions our board will make. It's premature right now to assume one way or another.

MR. TORGERSON: Kevin, I would agree with Mike. It is going to have to be eight out of eight, and again, it's in the center there. We still are going to be dealing with TVA energy, AIS and then the Canadian companies IMO. It's not like that's the only seam we have, but we are going to have to coordinate. And also as we do our planning, our planning will be regional, and we're going to cover such a huge area, we're going to be doing planning that encompasses things that I don't think they're going to care too much what happens in North and South Dakota or Manitoba, but it will impact the north central part of our area, and how that gets coordinated in, you can't say that it's all just with PJM, because we're going to have different areas. But, again, you know, five years from now, maybe there is a benefit in coming fully together into one RTO.

MR. KELLY: Thank you.

COMMISSIONER BROWNELL: I have just one more question, Mike, and I'm sorry Dr. Patton isn't here. Dr. Patton did I think by his own admission a self-selected kind of determination or study which raised some issues. Did PJM do anything similar?

MR. KORMOS: Unfortunately, I've not read Dr. Patton's study, so I'm not sure what he has done. We have obviously looked at the flows on our system, but I don't think we've taken it any further than that.

COMMISSIONER BROWNELL: And he raised the issue of Death Star being a potential outcome here. So you haven't?

MR. KORMOS: I'd honestly have to talk to Joe Bauer. Joe may have looked at other things that we didn't from operation. A lot of it seemed to be market manipulation, but I'd have to get back to Joe on that.

COMMISSIONER BROWNELL: Thanks.

CHAIRMAN WOOD: We're going to digest what we've heard as well as digest some lunch. If you all need to run, we're going to back and talk among ourselves, but this panel is welcome to say. We're going to finish discussing what we just heard. I won't prejudge what we're going to talk about, but we will pick up on this item when we come back from lunch.

Thank you all for your participation on the panel. We won't need the panel after lunch I don't believe. After that we'll do Mr. Museier and then the remaining items on the agenda. We'll see you no earlier than 2:45.

(Whereupon, at 1:45 p.m. on Wednesday, July 17, 2002, the meeting recessed, to be reconvened at 4:10 p.m. the same day.)

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AFTERNOON SESSION

(4:10 p.m.)

CHAIRMAN WOOD: So that was a good lunch.

(Laughter.)

CHAIRMAN WOOD: It wasn't the Capitol Grill, but it was a grill. I think I'm going to try to synthesize what I picked up from talking individually in compliance with the open meetings law with each of you all and see if -- and this is to wrap up on item A-4, the discussion about the Alliance Companies' choices in RTO selection.

I think we heard lots of issues. I think it's very clear to us that the real endgame is the virtual PJM MISO SPP marketplace. Recognizing that, I think we all feel comfortable considering approving on a conditional basis the choices of the former Alliance Companies as to their RTO selections, acknowledging that this approval should drive people to a common market sooner and with greater efficiency than we have seen to date.

It seemed to us that certainly a lot of the issues that came up today are admittedly transitional, although the longer that transition is, the more those problems fester, and I for one want to see the benefits of that $7 billion cost benefit study flowing to customers as soon as possible. So we will work on an order to talk about those conditions. I think certainly the biggest one in my mind is a plan to eliminate the rate pancaking seam between the MISO region and the PJM region.

I guess I think, Linda, to capture really what ERCA did in the earlier settlement between a lot of these same companies to try to capture that same kind of super regional benefit for all the users of the system in the entire region, and to do that at the front end of the transition here. Certainly one of the other conditions would be that NERC has to have complete and unconditional signoff at every stage of the process. That just kind of states the obvious, but I think that's what our job is to do.

We will perform internally through Mr. Hederman's shop a replication for our own records of what Mr. Patton's study did looking at all the relevant flowgates through the region and model those under the chosen format as well as a couple of others so that we know and can understand the full impact of that. It wouldn't be my first choice, but I think we're very interested in getting to a common market.

It certainly was instructive to me the line of questioning pursued by Mr. Kelly about some of the eight Order 2000 requirements that were already being met by the virtual ISO, the virtual single market, and that in effect the eighth requirement to have a single tariff was a natural followthrough from that, and it made a lot of sense to me.

Certainly an achievable single marketplace here is important.

I will take at their professional word all the witnesses who were here today, many of whom I know and trust, to deliver on that timeline. I want to see, however, before we do an order for PJM -- I see Mr. Grazier there. I know Mr. Torgerson had to leave. You, sir can get us -- I know it's been worked on. Jim had sent an e-mail. We're going to work on the Gent chart, all three entities, if they could get that to us, we'll have a look at that and see where we are on those dates.

I admit that I blanched a little when you said that you were going to be at LMP by the end of '03 and the integrated market would not be until '05. I wonder if we're all using the same software and the same tariffs, which I think originate at PJM, why we can't have everybody's efforts focused toward that. I want to see the Gent chart and have that be part of order. In fact, if we need to talk with you all about that chart before we do an order, it would be my thought to just do it. I don't even know what the posture of it would be, Cindy, but a simple order basically saying we're not planning on taking any further action to disrupt the companies' voluntary choices, and in fact urge you to get on with it.

And I will say for the four of us, we would urge the companies to get on with it today and not wait on that order. We'll talk about that among the four of us in the next two weeks and commemorate with I hope enough specificity and with sufficient clarity our expectations as to that timeline. That's the lynchpin for me, and if it's not met, that's a problem. But I'm pretty good at riding herd on timelines. I did it in one whole interconnection, and I think we can do it in what has grown to be a big part of the Eastern Interconnection here.

Anybody want to add before we move on?

COMMISSIONER MASSEY: For me, the ultimate goal should be a single virtual RTO for this whole region. The assurance that that will happen is what drives me toward agreeing to this, so I'd like our order to reflect that that's what the Commission wants to see in very clear, unmistakable terms, and that we'd like to see it as soon as possible, and that such a virtual RTO would essentially eliminate all the seams. All may be too high a standard, but you know what I mean, virtually all.

Otherwise, I would be uncomfortable with this choice because I still have questions about the interlacing and our engineers who were here. It seems to me that the electrical engineers are so happy that we're moving from 150 system operators to eight or ten that any configuration they feel like they can live with since it's a spaghetti now, and if they manage it, they figure they can manage the new interlacing seams as well.

I wish we could do better than that. And I think if we can move to this virtual RTO for this whole region and do so as quickly as possible, that would meet my concerns.

COMMISSIONER BREATHITT: I would agree with everything that you said, Pat, and everything that you said, Bill. I'm comfortable with this because it even furthers all the hard work that the parties did, and I don't think it is going to go to waste, all the hard work in doing the summer effort towards the seams and coming up with the ERCA.

But what it is, is the ERCA not just with the Midwest and the Alliance Companies, it will be an ERCA with the Midwest, the Alliance Companies and PJM. It spreads that work and that effort, and if a super regional rate can be developed along those lines, that's going to be great, too.

So I think that is the win-win for me, to the extent that that is built upon, it's great, because all that effort won't have gone for naught.

The reliability session we had this morning was very important and telling to me. There is some work to be done in that area everyone recognized, but it didn't say we can't go down this path. But they also recognized that we have economic decisions, political decisions with a small "p", market efficiency decisions and commercial decisions as we weigh in the reliability decisions too. I think that is reflected in each of what you thought about during our break.

So there's a lot of hard work to be done. The Chairman's ability for keeping the timelines and the stick-to-itiveness, if that's a word, is also going to be important in this effort, and I trust that you'll keep to that, Pat.

CHAIRMAN WOOD: We call it like a duck on a June bug.

COMMISSIONER BREATHITT: That's pretty good. I will conclude my comments and hope that we're getting enough verbal guidance here, and we're pretty up front with that, that the companies will be able to march forward.

COMMISSIONER BROWNELL: I'd like it to be 100-pound gorilla on an ant or something like that. I think we've all given a lot of thought to this. It's not as pretty as it might have been, but it is the reality that we're facing. I think it's all going to be about accountability.

We heard a lot of promises this morning. We also heard a lot of issues raised to which there did not seem to be answers, so I think part of that timeline is going to need to be getting beyond the promises and into the substance of how this is going to work and how we're going to address those market efficiency issues and those reliability issues. I think it's also going to be about how quickly we can deliver to customers more than the promise, but the actuality.

So whatever timeline is submitted, I would urge the parties to be as aggressive as possible. It worries me that it's so dependent on so many different kinds of agreements. I think the parties are going to have to be a whole lot more disciplined perhaps than they've been to date, because I think having made this potential commitment of approval, I'm going to be very concerned about getting on with it.

Thanks.

CHAIRMAN WOOD: You speak for all four of us on that one. That's the deal. So make it happen. We'll talk about this in two weeks.

In order to accommodate a timeline, I want to do the cases right now and then do the presentations after that. We'll do the two California cases now, and we'll follow that with Mr. Museler and the Western parties, Western Infrastructure update.

Okay, what have we got?

COMMISSIONER MASSEY: May I ask a clarification?

On what we just discussed, we will have an order presented for the next agenda?

CHAIRMAN WOOD: Yes. And we'll negotiate that between the four of us directly and get that short order drafted. It won't be on Friday, though. I'll just ask that in advance. Well, since no one is here to give the presentation. There you are. Come on in. I'm sorry. E-17. I thought you all were fooling around.

SECRETARY SALAS: They were waiting for us to call on them.

CHAIRMAN WOOD: And then E-48 will be next, and then we'll do Western Infrastructure.

MS. SHIPLEY: Good afternoon. My name is J.B. Shipley, and also Mike Coleman is here. Other critical members of the team are not sitting with us here but were essential. Len Towe, Colin Mount and Derek Rendell.

E-17 is an order addressing the California comprehensive market design proposal. The order continues the existing West-wide must offer requirement. It further establishes a bid cap of $250 per megawatt hour West-wide, effective October 1st.

The California ISO's comprehensive proposal includes a number of long-term market design changes as well as other measures proposed to be effective October 1st. With respect to the measures proposed to be effective

October 1st, the order approves automatic mitigation measures or AMP, including those applicable to local market power.

The order also approves a proposal to apply penalties for excessive uninstructed deviations. The order rejects the 12-month index as a mitigation tool but requires the information from such index to be filed weekly with the Commission.

Because the must offer requirement continues for California, this order rejects the ISO's proposal for an interim residual unit commitment process.

A number of market design features have been proposed for implementation by spring of next year. The order requires accelerated development of certain of these features by January 1, 2003, including the creation of a day ahead market, ancillary service market reforms, and certain proposed improvements to real time operations.

The order also approves a host of market design efficiency improvements.

With respect to the California ISO's long-term market design proposal, the order authorizes the ISO to begin spending funds to develop a locational marginal pricing system and other aspects of its full network model.

Finally, the order establishes a technical conference to address certain long-term market design features, especially resource adequacy.

Thank you.

COMMISSIONER MASSEY: Can we get a more thorough explanation of the AMP procedure? Because I think that is new for California, and it's extraordinarily important in the context of this order.

CHAIRMAN WOOD: I agree. For me, clearly it's the heart of the order.

MR. COLEMAN: There is an automatic mitigation procedure that had been proposed similar or allegedly based upon the New York ISO AMP proposal.

The order approves the use of AMP but makes a number of different changes from what the Cal ISO had proposed. They had proposed two tests, a conduct test and a market impact test in terms of whether or not AMP would be proposed.

The order approves the use of conduct and impact thresholds to determine whether AMP would be applied. The levels at which the AMP would be implemented have been changed from what the ISO had proposed. The conduct test, which is the initial test in which you would look at an individual bid to determine whether or not it would pass or fail this test, there are thresholds that would be the lower of a 200 percent increase or $100 per megawatt hour increase above a reference price.

To the extent that the bid, the individual bid would exceed those thresholds, the conduct test would in effect be violated and you would then look at whether or not that bid when aggregated with other bids that failed the conduct test, would affect a market impact test. The market impact test has similar thresholds, which again to the extent that the effect of the bids would be such that there would be a 200 percent increase or a $50 per megawatt increase in the market clearing price from these bids, those bids were considered to fail the market impact test, having failed the conduct test. You would then go to AMP.

A proposal which the order additionally adds, there is a third screen test which the ISO did not propose but which has been used in other AMP proposals, and that is a price screen test. The order would establish a third screen or a price screen test of $91.87 per megawatt hour, which is the current bid cap for the California market.

To the extent that market clearing prices are below the $91.87, the price screen, would mean that the AMP procedure which I had just proposed or those two thresholds would not be applicable. So basically, you would have to have the bids above $91.87 so that they would fail the price screen test, and then they'd have to fail conduct and market impact.

To the extent that the bids would fail all those tests, you would go to an automatic mitigation measure. The

ISO had proposed in that instance that those bids would be mitigated down to a reference price that would be established for each of the resources. There is a set of proposals or methods under which the reference price would be established. It is primarily a 90-day rolling average of what had been an accepted bid for that resource in the Cal ISO markets.

So, effectively what would happen is, to the extent that you have bid more than 200 percent or $100 more for conduct, 200 percent or $50 for market impact, and the market clearing levels are above $91.87, you would have your bid AMPed, so to speak, down to this reference price or reinserted into the bid stack for purposes of determining what the market clearing price is. That market clearing price then would be -- the person who had been AMPed would receive the market clearing price for that bid. That is what at least generally or at least staff has been describing to the Commissioners as the general AMP procedure which we are proposing.

There was a further proposal by the ISO to deal with local market power on the basis that they're even using AMP and with the additional use of their reliability must run contracts which they have, that there is still an ability for local market power to be left unchecked.

The order would modify the proposal by the ISO, and for instances where a bid is taken out of merit order to deal with -- the word is escaping me now -- intrazonal congestion, thank you, J.B. -- the AMP procedures which I have just described would be applied to that bid rather than the ISO's proposal that they would automatically mitigate down to in effect a marginal cost.

The order, in establishing the AMP procedure to be applied for local market power, would basically say that an out-of-merit bid would be considered to have failed the conduct test that I said. To the extent that the bid is also above the price screen of $91.87, which I also described, you would in effect then go to the market impact test and look at whether or not that out-of-market bid, although it does not set the market clearing price, if it were to have been included in a bid stack, whether or not that bid would have changed the market clearing price under the same thresholds as the market impact test which has been used before, and that is the 200 percent or $50 increase.

To the extent that that out-of-merit bid would have affected the market clearing price by that amount, although it would not affect the market clearing prices if it is an out-of-merit bid, the generator would be paid the higher of its reference price or the market clearing price.

That goes to the operation of the thresholds.

There are a number of other issues, Commissioner, that if you'd want to me go into in terms of whether or not, for example, AMP was proposed not to be applied when the ISO's forecast load is above 40,000 megawatts. We are rejecting that proposal and requiring that when loads are above $40,000, the AMP procedures which I have described would be applicable.

CHAIRMAN WOOD: Do I understand -- and I meant to ask you this the other day -- why did the ISO not apply that bid mitigation all the way up the bid curve when it's really tight in supply?

MR. COLEMAN: There is really not, at least in my mind, a clear explanation of that. But my thought on that would be that at loads of over 40,000, when you're getting into the very high peak demands of the ISO, and to the extent that a generating unit may be possibly subjected to AMP, I believe it was their intention that they did not want to discourage someone from offering into the market because they would be potentially AMPed, especially under the lower thresholds that they had proposed to be applied.

We have looked at that, and I think when you actually have loads over $40,000 --

CHAIRMAN WOOD: Megawatts.

MR. COLEMAN: Excuse me. Megawatts, that to the extent that you would have loads over that threshold, that would be where you would have the greatest concern that there may be the exercise of market power, and therefore we believe that the AMP proposal should be applied.

CHAIRMAN WOOD: I think it's important to have that protection be really complete, particularly at the peak hours. I do have to say, the AMP tool, certainly you explain it very thoroughly, but for just kind of a general audience, the AMP tool is one that, as we point out in this order, is appropriate to allow scarcity signals to go through but what it attempts to do as surgically as we can, try to make sure that market power reasons for price increases are in fact squelched.

And that's a delicate balance. I know from the New York experience it's been observed really on peak days and at congestion. So I think it was real important for us to patch that hole that the ISO proposal had left in there, and I appreciate you all catching that.

COMMISSIONER BREATHITT: How does it treat imports by AMP procedures?

MR. COLEMAN: The ISO had proposed to include imports as subject to AMP and the order would do as they had proposed and have imports subject to AMP.

COMMISSIONER BREATHITT: And we found that that was -- does it say why we thought that was reasonable? Does it go into a lot of detail?

MR. COLEMAN: The reasons that the ISO had given for both having imports and hydro resources subject to the AMP was the significant amount of hydro resources that are relied upon to serve the California market and the fact that California has historically relied upon imports to be able to serve their peak needs.

COMMISSIONER BREATHITT: Does it include hydro resources? All imports coming in, whether it's hydro generated or thermal?

MR. COLEMAN: Correct.

CHAIRMAN WOOD: One of the changes or one of the things that made this easier to deal with was the instead of going and doing a reference price on every generator in the Western Interconnect, what the Cal ISO had recommended was determining reference prices for each scheduling coordinator who provides the energy at each scheduling point across an intertie. So I guess that really is a proxy for what the reference price would be. But I think that is probably the most pragmatic way to handle it. Otherwise, you've got ricochet and megawatt laundering, and we don't need that.

So I think it's important to keep that in there.

MR. COLEMAN: Mr. Chairman, actually by mentioning the calculation of the reference price, that has reminded me with all the number of things that are included in this order, I think one of the things that our presentation did miss that I think is significant here too is that the calculation of the reference price or the baseline upon which you would be evaluating whether to AMP a bid or not, there is concern with respect to the amount of discretion that could be used in establishing these reference prices for the generating units.

And therefore, the order directs that an independent entity be required to calculate these reference prices, and the order sets forth a timeline in which the Cal ISO is to issue an RFP and to select an independent entity to calculate these reference prices. And all of that would be accomplished in the identity of that entity that would be calculating the reference prices or is to be reported to the Commission by I believe it's September 15th.

COMMISSIONER BROWNELL: Can either of you talk a little bit about the timelines for the implementation of not the mitigation portion of it, but the California market redesign portion?

MS. SHIPLEY: Yes. California had given us its proposal in three stages. The first stage is what will go into effect on October 1st.

The second stage was proposed to be I believe spring of next year. We have asked them to accelerate that to be ready by January 1st. That phase two includes basically the creation of the day ahead market. That's the biggest improvement. Also reforms to its ancillary service market and changes to the structure and timing of the real time markets.

And what that achieves is, it eliminates the balanced schedule requirement, which as been problematic for them. We encourage them to get that done more quickly. We require a filing by October 21st I believe.

COMMISSIONER BROWNELL: Going back to the AMP and the date by which the independent entity is to be chosen and then having some work in progress, the AMP provision does not kick in until that provision is satisfied. Is that correct?

MR. COLEMAN: Correct.

COMMISSIONER BROWNELL: And we're getting quarterly reports on the AMP and looking at the thresholds? Because I think we all recognize that however brilliant we are in the mitigation tools, they always have some surprises. So that's quarterly?

MS. SHIPLEY: Yes.

MR. COLEMAN: Yes. That is one of the things that's in the order, and I think maybe it's also helpful to point out too that the AMP procedure, which we're finding is necessary, is being applied to a zonal congestion, three-zone congestion management system at this time because the full network model is not proposed to be developed for about another year.

I think having the reports that come in on the end measures I think will be especially helpful in light of the fact that this is not a full nodal system to which they are applying the AMP. I think that that information will be helpful to us in terms of understanding the effect of the AMP procedures on bidding and actual prices in California.

COMMISSIONER BROWNELL: Hopefully, it will give us a better picture of what's working and what's not as we move to that fuller market. And I'm glad we've accelerated the timeline, because I worry that we continue to rely on what can only be described as more than belts and suspenders in terms of mitigation when I think we're all quite passionate about protecting customers. I think the ultimate protection for customers is having the full market resources available and real price signals sent.

I'm glad we've put these together, and I hope we don't get so consumed by mitigation and so reliant on mitigation that we lose sight of what the endgame here is, and that is really doing right by the customer and bringing the real market forces to bear.

CHAIRMAN WOOD: Amen. Had we choreographed this as eloquently as I'd had hoped in this meeting, we would have been prefaced by the Western Infrastructure assessment, which quite frankly for me, we began the effort to prepare for this ruling back in April, knowing that the May 1st filing was coming from the ISO.

I asked staff to begin the Western Infrastructure assessment so we would have a factual record on which we could base an appropriate balanced remedy here. And I have to say, a year ago when I voted on the mitigation, I had hoped that we would have been much further down the road toward I guess as you would call it, the long-term health, as we could be, and we're not. I think there are certainly directionally, improvements in the right direction. Certainly the rain and all those things will happen when the good Lord wants them to happen, but the long-term fixes are not here.

And I think it's reluctant for me that we have to continue to really impose the mitigation on this market. But I think it's the appropriate thing to do based on the facts.

We don't have the balanced market rules in place, although this order does a lot to not only, as I think, Linda, your questioning pointed out, the balanced market rules were filed here by the Cal ISO in large measure. They look exactly like we're learning and studying is the appropriate way to go for everybody else as well. Aggressive timelines on those.

The infrastructure issue is outside our realm. I mean, a lot of that we can cajole and help and support and buttress and all, but ultimately that's an investor and a state official, state regulator, state permitter, local officials, that make the infrastructure happen in California. And so it's going to be a joint effort going forward to make sure that that happens.

I would have loved to have been able to say our order last year fixed everything, now let's go to the normal tools that happen in New York and PJM and Texas and everybody else that has organized markets, but I don't think we're out of the woods here yet. So it's not with a whole lot of joy, but with I think a realistic appreciation for what the facts are and what our responsibilities are that we endorse the program here, which I should add was largely what was recommended to the Cal ISO board by its own professional independent market surveillance committee.

Mr. Wolak and the other folks on that committee have earned a lot of respect here and elsewhere in the country, and their original proposal before it was modified by the board is what we largely adopt here today. And I think that's a role that I hope we can see elsewhere in the country, that kind of objective, independent smart people who we can really leverage their talent and brainpower as we analyze these tough issues and really try to hit the balance between our joint requirements to provide reliable service and to do it at just and reasonable rates. We've got to do both, and I think this order hits the pitch to do that. But it also acknowledges that everybody, not just the FERC, has a role here to play in getting it ultimately out of the ditch.

COMMISSIONER MASSEY: So just to summarize it for me, there's an absolute $250 bid cap for the Western Interconnection. Am I summarizing that correctly?

MR. COLEMAN: Yes. That's the easy part, Bill.

(Laughter.)

COMMISSIONER MASSEY: All right. I've got that one.

(Laughter.)

COMMISSIONER MASSEY: So the AMP works underneath that. That $250 bid cap, by the way, is for the Northeastern ISOs, it's $1,000 I think for all three of them, and Texas, too, to the extent that's relevant.

(Laughter.)

COMMISSIONER MASSEY: It may be relevant someday if Congress does the right thing. But it's 250 bucks. All right.

Underneath that $250, the AMP procedures apply, although they don't apply if the market clearing price is under $91.87, AMP does not kick in, right?

MR. COLEMAN: Right.

COMMISSIONER MASSEY: All right. So AMP applies between -- when the market clearing price would be between $91.87 and $250?

MR. COLEMAN: Correct.

COMMISSIONER MASSEY: That's where the AMP procedures kick in. Now the AMP procedures are complex, but there are essentially two screens. You've mentioned three, but I've already taken care of the $91.87 screen. The first screen is, if the individual bid is 200 percent or $100 above my reference price if I'm a generator, if it is, you go to the next screen. And if I'm having an impact on the market clearing price of above $50, I am AMPed back to the $50 level. Is that correct?

MR. COLEMAN: It's 200 percent or $50. If it's an effect on the market clearing price, you are AMPed back to --

COMMISSIONER MASSEY: I'm AMPed back to my reference price. Okay.

MR. COLEMAN: I don't want to add the complication. You are given a default bid which is equal to that reference price so that you're placed back in the bid stack, and then they look at what the market clearing price would be with your bid AMPed down to that reference price, and then you are paid the market clearing price, because you're under a single price auction in California. So basically you recalculate the market clearing price with that bid AMPed, so to speak.

So that the AMP that you get would be, you don't get your original bid. You would get the calculated market clearing price.

COMMISSIONER MASSEY: And this whole process is very similar to what the New York ISO uses. Bill Museler is out here. I think David Patton came up with this scheme. He testified earlier today. He developed it for the New York ISO, and it's very similar to what we're requiring for California.

But when you say you're AMPed, it essentially means your bid is changed. Your bid is reduced, it is mitigated before that price is charged and before it has any impact on the market clearing price?

MR. COLEMAN: Correct.

COMMISSIONER MASSEY: So this is on the front end. So the Commission is saying within these limits, we believe prices will be just and reasonable and there should not have to be any two-year-old refund cases with these procedures in effect. So we're handling this on the front end. It seems to me that's the way I read it.

MR. COLEMAN: I would hope that we would not have any more two-year refund proceedings under any circumstances, Bill.

COMMISSIONER MASSEY: It seems to me to be the worst way to have to handle these problems.

Then I would like to underscore that in the long term, what has been proposed to us with locational marginal pricing and the whole long-term revamping of the California market has got some nits and gnats. We're going to schedule some technical conferences to work out some issues, but it generally sounds pretty good to us. I think that's what this order says. Am I correct in that respect?

MR. COLEMAN: Yes.

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COMMISSIONER BREATHITT: The A of AMP stands for automated. To go into a sort of broad description of automation versus people doing this, it's essentially done by inputs into software and it's automatically done, correct? Once this independent monitor certifies the reference prices, those will be the inputs and then it's automatically calculated and done by a computer.

MR. COLEMAN: I think it becomes ministerial at that point to the extent that you have a reference price for a resource that you can take. Once their data is submitted, you're just looking at a comparison of the two. To the extent that you were in the mode where you're calculating either the conducts test or the market impact test because if the market clearing price is above 9187 it becomes ministerial looking at the difference between those two, and calculating what the percentages are.

COMMISSIONER BREATHITT: Is the computer running 24 hours a day, seven days a week, or does a control room operator decide when to push the software button and kick in AMP procedures? How does that part work?

MR. COLEMAN: The AMP procedure in California, you have to realize right now there is no day ahead market in California. Things are done in real time. The ISO came in when it proposed to apply AMP and indicated that because they run the ten minute market, it would not be feasible for them to be able to calculate these AMP prices and comparisons, and still meet their ten-minute dispatch. What they had proposed to do was to run this process at the time they get sort of their final hour ahead schedule. Then they would run it at that time, so is it running continually? It will be run for each final hour ahead schedule but there will be a time certain in which they will then be running that.

There is existing software that they use right now in terms of a transmission constrained unit.

MS. SHIPLEY: There's actually two stages when they run AMP. One is the day ahead scheduling, the TCUC software, and then again in the hour ahead scheduling time period.

MR. COLEMAN: Those are discrete time periods in which they do that once the day ahead market is created for California, and that is something which the order requires the ISO to accelerated for a January 1, 2003, rather than some time later on in 2003 implementation. That AMP procedure would then be applied.

COMMISSIONER BREATHITT: Nora asked the question that this doesn't begin until the independent person is hired and the reference prices are calculated. Then it begins.

MR. COLEMAN: Correct.

COMMISSIONER BREATHITT: In what month? Monthly?

MR. COLEMAN: We would expect that it would start October 1st. The local market power --

COMMISSIONER BREATHITT: Our plan is September 30th. This would begin October 1st.

MR. COLEMAN: This begins October 1st. The order does require that until this independent entity is in, in which the reference prices can be calculated, you can't start implementing an AMP process. The expectation is that that will be done in order for them to be able to implement that process beginning October 1st when the other mitigation measures and other market efficiency proposals go into effect October 1st.

COMMISSIONER BROWNELL: I'm assuming, given some of the issues that have arisen about the accuracy of data and the strength of the systems that support the ISO, that either when we send some folks out there to be on the ground, or certainly within the ISO itself, we're going to get really comfortable that they have the infrastructure to support all of this.

MR. COLEMAN: I would certainly think so. The accountability and the accuracy of the data, I think, is important to the integrity of the market and it will be something we'll certainly be looking at I think getting the information on what the AMP measures are would go to that too.

CHAIRMAN WOOD: One of the things, just to kind of dumb it down, market power, we've learned, academically and in the real world, is exercised by either physical withholding or economic withholding. This order addresses each very frontally with a very potent tool. Physical withholding is addressed through the must-offer requirement which I think quite frankly was really the jewel of our decision last year. Much more even than the formula and all that was the requirement that told generators actually for the first time you have an obligation to put your uncontracted for capacity out for sale across the entire West. That addresses the physical withholding.

And then the AMP, as we have talked about it, backed up by the absolute $250 bid cap, is the tool to address economic withholding. The nice thing about it, as Bill pointed out -- and this is all up front and Linda you pointed it out too -- is it doesn't have the refund. So I'd rather not have to do mitigation. Hopefully these tools will be observed only in their non-use but if we need them, they're there. They are defined and they are prospective. So it's a good batch.

Actually, the most important part of this order when we look back on it a couple of years from now will be the long-term measures that California proposed that we largely adopted enthusiastically. I know you guys will be out there in August to do some tech conferences with the stakeholders and I know from Bill's presentation earlier that we are committing and have informed the ISO that we will be having people in the ISO offices going forward to oversee the implementation of the short-term and the long-term plans, and be as helpful as we can but also keep an eye on things, making sure that they are moving forward as we expect them to. It's an important market. We need to get it back on its feet, see what we can do and work with the state to see what the state can do to put it back together. I think this certainly should be a good step in that direction.

COMMISSIONER BROWNELL: I also wanted to say thanks to the team, J.B. Collin, Leonard, Mike, and the cast of thousands who were writing up until probably about half an hour ago or an hour ago. This is certainly who were here last night as I was leaving as he sun was going down. As we were tinkering around the edges, I think you've got a good product. I appreciate the hard work and the patience.

CHAIRMAN WOOD: I appreciate that we got this out at this meeting. I think it helps the ISO. It gives them some time to make a few adjustments. I do think by doing the must offer, we took a big chunk of what would otherwise be pretty tedious work off of the deck so I think not only do we have a better substantive outcome but it probably helps the process too. So probably what I thought we voted on a year ago when we did the first mitigation order to end all mitigation orders but its direction is up and out and I think we will watch it as it goes forward and make the adjustments as appropriate for the state of the market infrastructure and for state of the market rules.

COMMISSIONER MASSEY: I think I'm right that there is no expiration date on any of these mitigation measures in the order?

MR. COLEMAN: There is no express dates in there. I do believe that the order is, at least in certain places, where the parties had asked that we review levels, and I think that is certainly within the Commission's discretion to do that, or parties to file to ask to do that. But as we have a January 1 implementation of certain market design features, and as you move toward the implementation of their longer term market design, we will have those filings and I think that will provide us with an opportunity there to the extent we may need to make some mid-course corrections. But I don't think we need to make any. I think that there are opportunities but you are correct; there is no express sunset date for these mitigation measures at this time.

COMMISSIONER MASSEY: I'd like to be clear. I am supporting this order because it retains the must offer condition which I think was critical and was the centerpiece of our earlier orders and I'm glad we're extending it. And number two, I think the AMP can work very effectively as a mitigation tool. I would ask those in California who might be concerned about the Commission lifting the bid cap $250 to take a close look at the AMP and the protection from the exercise of market power that it affords.

COMMISSIONER BROWNELL: I just want to say one thing. Bill brought up an important point. While there is no end date, I would hope that in subsequent filings and indeed sa an exercise in kind of what are we going to be when we grow up, that we and the participants in California will get some benchmarks in place so that we'll be able to say when is it that we'll be able to say when those market forces work, when is there sufficient infrastructure, what are the kind of things we're going to be looking at so that we can in fact get to maturity sooner rather than later.

COMMISSIONER MASSEY: Aye.

COMMISSIONER BREATHITT: Aye.

COMMISSIONER BROWNELL: Aye.

CHAIRMAN WOOD: Aye. Thank you all.

SECRETARY SALAS: The next item for this conference is E-48, Marie Delta Elosino with a presentation by Eugene Grace.

MR. GRACE: Good afternoon. Draft Order E-48 concerns the California ISO's governance structure. The order finds that the continuation of the existing board will hamper the ability of the California ISO to implement a redesign of its energy markets and in turn this Commission's ability to ensure non-discriminatory transmission services and just and reasonable rates in the West. This is due to the fact that the state control board is not capable of operating its transmission facilities on a non-discriminatory basis. Furthermore, the board, as presently constituted, continues to be in non-compliance with certain past Commission orders.

Because of these problems with the existing board, we direct the California ISO, following the procedures outlined in the order, to adopt a two-tiered form of governance by January 1st, 2003. The top tier will consist of an independent, non-stakeholder board but the lower tier will consist of an advisory committee and its stakeholders which may recommend options for the board.

The Advisory Committee of the California Electricity Oversight Board which will serve as the state's and it's agency's representatives in advising the board.

CHAIRMAN WOOD: I support the order.

COMMISSIONER MASSEY: Well what persuades me to support the order is that the state of California is essentially a market participant now through DWR and our independence requirements that we have applied with respect to all ISOs and which we are applying with respect to RTOs are really the centerpiece of that whole policy. I do not think the Commission can continue to ignore serious problems with respect to the independence of any ISO or any proposed RTO. Not only must it be independent in reality, but independent in perception.

It is my view that, sa presently constituted, the California ISO Board fails both tests and must be reconstituted according to the plans set out in this order which has my support.

COMMISSIONER BROWNELL: I think in large part, much of this order derived from the operational audit that we did. Bill I think confirms your comments and also suggests that this was in fact the first priority of reestablishing the Cal ISO as independent and fully operational. There are other issues the audit pointed out that we'll be dealing with later, but correct me if I'm wrong. The report said all other things flow from this and it's important that you start here and give us a lot of examples of why. Is that correct?

MR. GRACE: That is correct.

COMMISSIONER BROWNELL: Thank you.

COMMISSIONER BREATHITT: I am pleased that we are voting this order out today. It's a very comprehensive order, it's 31 pages, I urge everyone to take some time to read it because there's a lot there. This will begin to reflect even more what we've said about the independent makeup of boards and their selection and the stakeholder process and the advisory councils that will be able to advise boards and make recommendations to boards. I have been waiting for this order for some time, since December 15th, 2000, when we initially said that the board needed to be independent. I agree with my colleagues that there was an order of things to do in California but we did put this off to give parties time to deal with crisis mode. We all decided that the time was right to do this now. I would have preferred that this had been done a little earlier but I'm glad we are issuing it today. It's a very comprehensive, good order and I think it will be welcomed by those who have complained to us. It's styled Mirant, Delta, Milton Protero versus Cal ISO on and on.

We've had a lot of parties complaining that we've needed to do this and we're doing so today. I think it's a good order and it has my support.

CHAIRMAN WOOD: I'm ready to vote.

COMMISSIONER MASSEY: Aye.

COMMISSIONER BREATHITT: Aye.

COMMISSIONER BROWNELL: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: The next item for discussion is E-36, Funding Requirements for Electric Utility Service Agreements with a presentation by Gary Cohen and Charles Faust.

MR. COHEN: Good afternoon. E-36 addresses the request for rehearing and clarification of Order Number 2001, the Commission's final rule establishing revised public utility filing requirements. The draft order affirms the finding in Order 2001 on confidentiality, the timing of electric quarterly reports, and the need to report data in a disaggregated manner. The draft order also clarifies the transaction end date and transaction begin date data elements and reporting of book out transactions.

In addition, the draft order vacates footnote 30 of Order Number 2001 which raised issues about the standard of review the Commission would use in reviewing unfiled market-based rate agreements and provides that the Commission will instead address Mobil Sierra issues generically in a future proceeding.

Finally, the draft order denies requests for a stay and requests for a 29-day extension for the filing of the first electric quarterly report which is due on July 31st. Thank you.

CHAIRMAN WOOD: The only thing I wanted to call attention to here is the important issue on the Mobil Sierra discussion that we are taking out of the original order in favor of a generic proceeding. I commit to getting up, for all of our consideration by the next meeting, a statement of policy by the Commission on the Mobil Sierra language for us to discuss. It's an important issue raised by parties here. But it's better not in a footnote but as a stand-alone policy in this era of trying to understand what the Commission thinks about contracts and what the standards of review for such contracts ought to be.

I'll support the Order 2001 and appreciate its quick turnaround by the Staff. I appreciate you all doing that.

COMMISSIONER MASSEY: Aye.

COMMISSIONER BREATHITT: Aye.

COMMISSIONER BROWNELL: Aye.

CHAIRMAN WOOD: Aye. Mr. Museler, you get a free care provision just for waiting all day.

(Laughter.)

COMMISSIONER BROWNELL: And now everybody knows how we feel on that MOU that started in 1998.

(Laughter.)

SECRETARY SALAS: Mr. Chairman, this is number A-5, Northeast Regional Transmission Organization, the presentation by Mr. William Museler for the New York ISO.

Also at this table for this item are Dave LaPlant, Michael

Kormos, Charles King, and for the Commission it is now John McPherson and Steve Rogers.

MR. MUSELER: Thank you, good afternoon. It occurs to me that David Patton and the New York ISO made an error in not copyrighting the AMP.

(Laughter.)

MR. MUSELER: I think we could have paid for a lot of market improvements. Thank you for having us here. As you know, we are here as a follow-up to our meeting about a month ago where we presented the status of the seams issues between the Northeast ISOs and by extension the IMO.

You directed us to solicit comments from the market participants in all three areas and also from the PUCs. You also asked them to respond directly to you. We did also look at the replies they made directly to the Commission so what we have here is the seams action plan that has been updated with the major emerging coordination issues and those that have been on our plate.

We provide a timetable for resolving those issues. We have added a number of issues. They're labeled as new as a result of the survey and the information we got from both the market participants and from the PUCs. We've actually provided in the handout information a number of detailed sheets, all of which have the projects that resolve these seams issues numbered consistently. You're familiar with the overall timeline which we used last time.

Now we've reorganized this as a result of discussions with some of the market participants in terms of the major seams issues. And then all of the projects that address those seams issues. That's the second part of the handout that's this blue and yellow colored one that we're not going to go through, but we think that makes it easier to say what specific projects in the various ISOs will resolve these issues and what is the schedule for those specific projects because every issue, because they're multifaceted, has quite a few projects associated with them.

So all of these documents tie together and the only one that I'm going to be speaking from is the overall PowerPoint presentation. What we did, as a result of our last meeting is conducted reviews with the individual stakeholder groups for all three ISOs so all of us individually went to our stakeholders,

(Slide.)

met with our PUCs and we also got all three ISOs together at the officer level along with representatives of all the stakeholder groups in all of the ISOs, and we did that by inviting the committee chairs and co-chairs of the three ISO committees of the stakeholder committees. That meeting was kind of the consensus meeting where we put all this information together so these documents include the comments from all of those meetings.

Obviously we're going to continue to update this list. One of the things that at least we believe you called for, is a regular updating of the status of the seams issues among the ISOs that you told us to get together with. And in fact, we plan to do that along the same lines that the New York PJM Agreement calls for so as of October would be the next time we would update this and submit it to you.

There's also all of the ISO CEOs in the U.S. and Canada are getting together in the middle of August and we believe certainly the Midwest ISO and we've talked with Jim Torgerson about this and the IMO, and we think that it makes sense to incorporate those contiguous ISOs in that update plan for seams issues, so we would plan to do that.

And then the quarterly report will have all of that information in it as well.

(Slide.)

The major issues that are treated and these headings are the identification of the seams issues and then the projects are associated with each one of those. I've got some comments on a few of them, but I'll go through the rest of them very quickly.

The transmission service issue has to do with the consistent treatment of transmission service products firm transmission versus non-firm transmission, etc., and durations and the length of time that transmission contracts are good for. ICAP deliverability obviously has to be consistent if the products are going to be able to be traded across various borders and we think between New England, New York, and PJM we have the appropriate deliverability rules in place now.

However, what we don't have yet and hope to have by the end of the year is a consistent ICAP product so the product will be the same throughout the three ISOs. Right now, there are some differences and everybody agrees that we need to get to the same product definition.

The next step after that, once we get to that point, the next step that the working group will have on its plate is how to get to a single market for ICAP. Since it's a batch process, it's possible to do that even with individual day-ahead markets and real time markets. Transaction checkout failure continues to be a very important seams issue. We have made a lot of progress in that regard but we had a recent example between New York and the IMO about how difficult it is to predict the future in that regard before the IMO went live. We had a lot of coordination meetings. In fact, we have procedures between the two ISOs to make sure that the transaction checkout process worked properly and we were treating the transactions properly..

As it turned out a few days ago, we had some major checkout failures despite the fact that the IMO and the ISO happen to use the same software for the hour-ahead evaluation. We both use ABB software, so I pointed out, and we were able to turn that around, get those procedures operating correctly and get that problem behind us. So it's not a problem today, but it did result in a fair amount of transaction cancellations and that cost people money and we are very sensitive to that.

I point that out just to point out the interrelationship of the procedures between the various control areas. They tend to be extremely important in terms of what can cause transaction problems, so it's far from just a software compatibility issue. It has to do with operator rules and checkout procedures which are not automatically reconciled between any of the ISOs at the present time.

Transaction scheduling has made a lot of progress but is also, as you can see in the additional material, there are projects associated with virtually all seams issues that still have problems on there that need to be resolved. Curtailment. The appropriate curtailment rules in each control room so that the other control rooms know which transactions will be curtailed in which order, under what conditions, continues to require attention.

And transaction ramping which is a subset of scheduling problems also has a series of actions that need to be taken. ATC/TTC differences in calculations and postings, there are already a number of things that have happened this summer. PJM has one additional posting coming in this month. So we are making progress in that area but there are still additional features that market participants want that are on the list, and I've already talked about the capacity markets a little later.

Interconnection procedures.

(Slide.)

Hopefully, at least we're hopeful that the SMD will give us some additional guidance in this area. Clearly there needs to be more guidance in this area and there needs to be more work in this area. As an example, in New York, which has been in an evolving state with respect to the interconnection procedures. We just got through issuing the class of '01. This is the way we do it in yearly classes. We just finally got through issuing the class of '01 late in a very contentious process that went on for over 18 months. That probably hasn't landed on your desk yet but that's going to be appealed. So the certainty for the developers in terms of being able to get through these processes and then have some hope that it won't drag on for another three to six months, is a real problem, and I'm hopeful that whatever guidance the Commission has will help us in this regard so we won't have the different interconnection policies get litigated individually.

CHAIRMAN WOOD: So the nature of why that was so slow was due to different provisions of each different utility?

MR. MUSELER: No. It was due to the original New York approach to interconnections, was heavily litigated at the time. The Commission finally gave us an order and actually changed the responsibility correctly in our opinion for having the authority on the interconnection procedures from the TOs to the ISO. That delayed it because the original New York tariff in that regard had given that responsibility to the TOs. That's how it had been filed.

When the process started, there were protests, the Commission acted, but right in the middle of the process, we switched horses. The ISO took responsibility, the rules were still very contentious and in fact the rules are different for the class of '02 than they were for the class of '01 and it is an improvement in our estimation. So we were acting in this continuous evolution of who's in charge and what the rules really are. I'm just suggesting that, you know, hopefully there's a national standard for this, and whatever it is, we all adopt it and that will certainly never eliminate litigation but it should at least reduce it considerably.

In New York City, this is a major problem for us in New York City because of the lack of new generation that's being built. There's very little generation. The only generation under construction in New York City is small combustion turbines. The big steam units need to have certainty in terms of their interconnection charges so the developers can actually make commitments and get financing.

I think there are similar problems, maybe not as difficult as ours, but I think other ISOs have similar problems as well. One of the major comments we got from several of the PUCs and several of the market participants was the issue of pancaking the through and out rates and that clearly was not in our last presentation. As Commissioner Brownell pointed out this morning, with respect to the costs or benefits of resolving some of these seams issues, from the Commission's studies as well as PJM's studies and New York's studies.

The single biggest seams issue with respect to value to the market is to eliminate the pancaking. It ranges on whose cost/benefit study you look at. Anywhere from a regional basis for the three ISOs, from $200 million to $400 million a year. That clearly should receive very high priority. There are in the detailed information to the extent that the ISOs have the ability to deal with this exclusively to some extent, and we don't have unilateral ability to do that, there are a couple of instances in there where we do have direct plans.

The NERTO filing that will come before you some time in early August has a date certain for eliminating of pancaking between New York and New England. The agreement with the IMO doesn't do that but it basically agrees to study that situation with an aim towards eliminating pancaking and having a recommendation by a date certain. And I've spoken to Phil Harris about that in the context of the New York/PJM Agreement.

Clearly this area, particularly if it's going to move quickly, will require leadership from both the Commission and the state PUCs. The elimination of those rates and the concurrent restoration in some fashion of the revenue losses to the TOs have got to be resolved. That's something that really can be resolved much quicker if the regulators involved were to take some initiatives.

CHAIRMAN WOOD: You heard that was clearly an issue in the last folks we dealt with. On your other pivot, any sage advice what the best way to handle that procedurally would be. If you don't, I mean, don't worry about it, but I just wondered if you had any wisdom to share.

MR. MUSELER: It is one of the things on the agenda for all of the ISO CEOs when we get together in mid-August, so let me not freelance in that regard. There are some emerging issues. These are not totally new but they are important. In fact, they've been around for few years but we've kind of not dealt with them recently. That's intercontrol area congestion and parallel flow management. There's a pilot that's underway between PJM and New York with respect to intercontrol congestion management. Hopefully that pilot will go well in the western part of New York and the eastern part of PJM. It's a relatively small pilot project, but hopefully it will give us some guidance going forward.

So there's not a lot of detail beyond that in this particular area right now. We recognize we need to develop that now because if we can, if we are able to redispatch across the control area boundaries in order to relieve congestion, there is some real benefit associated with being able to increase transactions as a result of that.

(Slide.)

The last item is the scheduling of controllable tie lines. This has turned out to be a more difficult problem than we originally thought. This is basically how controllable ties, HVDC in particular, will operate in a market context. We know how to operate them from a system context. The cross-sound cable between New York and New England is going to be operational in certainly the next month. But integrating that fully into the market to allow that to be part of both the day-ahead market and the hour-ahead dispatch is proving difficult from a market rules standpoint. We're working on that very closely with New England, and hopefully that will blaze some trails and that will be applicable to other HVDC or PAR type applications. But we are expending a lot of time to try to get that right. And I'd say that's a real market design issue that I don't know. I suspect it may not be the level of granularity that you address in your SMD but it will come back to you, I'm sure.

CHAIRMAN WOOD: Where would that be on here? Is that what Number 37 is?

MR. MUSELER: Twenty-nine.

CHAIRMAN WOOD: Got it. Right.

MR. MUSELER: Thanks Dave. Moving on to market standardization,

(Slide.)

all of the CEOs of all of the RTOs asked me to address this as part of this discussion. I think the Commission's well aware that we've been working in the NAESB process to try to determine the appropriate role of the ISOs and RTOs.

Unfortunately, we have not been able to reach a mutuallyagreeable role for the RTOs. We've been particularly frustrated by a minority in the last NAESB meetings being able to prevent reconsideration of certain potential outcomes but we're going to continue to work in that process. We do think that we, the RTOs and the ISOs, have an important, independent role from the other market participants. We think it is inappropriate for us to be in the same sector as a market participant who has commercial interests in the outcome of these rules, and again as part of our getting all of the U.S. and Canadian CEOs next month going to try to form a position that we may come to you with, although we will continue to work in the NAESB process to try and see if we can get an agreement there.

This is very important to us because we think, to some extent, we are an extension of the FERC here in terms if we have to implement not only our tariffs and the agreements that you approved, but we're going to have to implement these business rules. We're going to have to implement NERC's reliability rules, and we think that we need to have a reasonable amount of say in how those rules are put together, if they're going to be successful.

CHAIRMAN WOOD: Before you hop off that, Bill, we've watched this with interest from here. An advisory role there is critical. Quite frankly, when those rules that are codified come to us for inclusion, which all the gas rules do, you've all got a problem with those. You know we're going to be listening so I wouldn't get too caught up in whether you vote or don't vote or not. You are our extensions in the frontline.

MR. MUSELER: I think the preponderance of opinion, one of the options was to form a sixth sector which would have voting rights but I think most of the CEOs at least believe that's not the critical component. We'd prefer to not come in at the last minute and have a problem, and it becomes a problem to you. So what we're really aiming for is some role in this process that we can get an iteration at the NAESB level so that when it does come to you, either there is a confluence of agreement on it, or at least you get both arguments at the same time. The former is obviously preferable to the latter.

CHAIRMAN WOOD: I know a lot of the electric folks haven't had as much experience with GISB but just on behalf of the half of our agency that has, it really gets very difficult to do policy issues there. We seldom rely on them for policy issues. We rely on them, we'll make the policy cut, you figure out the detail work as to how to make it happen. As you will be the implementor of that detail work, I think that clearly makes a nice circle. Here's a policy public interest decision from FERC, here's a group of stakeholders you have to work through to implement it, or have to work through it and live with it, and you're the guy that implements it.

There's a nice triangle effect there and I hope that can be a good template for fixing. One of the things that I'm thinking about in looking at your slide here on market standardization and the NAESB issues is GISB didn't deal with coordination between pipelines and NAESB isn't going to do that either. That coordination has to come through exactly what you guys are here to do today, which is to get an iron and just iron on those things until they disappear. We're not counting on NAESB to do that, we're counting on you all. And in this process, you're the template we're going to use for seams resolution everywhere else. It may look a little different with PJM and the MISO because of the nature of their going together but it's all kind of different shades of the same color of what we did earlier today, and the follow-up to that more particularly what you all are doing here is coordinating the different ISOs and RTOs ultimately in the Eastern Interconnect.

Standardization, yes, we'll develop that through NAESB but the coordination of this stuff is front and center, what has to happen here and will be a big part of our mutual relationship for many years to come. Recognize NAESB for what it's meant to do. It's just to implement the standardization half of the world but the coordination half of the world, you're the front seat, you're the only seat actually. We'll work on that over the years but I think that's the way to think about the way NAESB fits into the universe, at least from my perspective.

(Slide.)

MR. MUSELER: The last slide just reemphasizes the areas that are our highest priorities right now. The controllable tie line modeling because we have one more HVDC coming on line and we need to integrate that into the markets. It's clearly important. There's a whole panoply of transaction ramping, scheduling and checkout projects, vital because those affect transactions on a day to day basis and we have made progress but we do have a lot of things to do, and there's still a bunch of oh my goshes out there as I described earlier between New York and the ISO. I think we made very good progress in the ICAP area but the common ICAP product, I think, is a goal we absolutely want to drive by the end of this year.

So we propose to continue to update you on a quarterly basis. We're going to roll in the IMO and the MISO and I would ask if Mike or Dave want to add anything at this point.

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(No response.)

MR. ROGERS: I have just a few questions, if I could, Mr. Chairman. Picking up on the point you made a few moments ago, Mr. Chairman, I wonder if there are any legal or regulatory restrictions the ISOs are facing in achieving greater coordination, since its information exchange?

MR. MUSELER: We don't see any. We've had to execute confidentiality agreements between us, but we've done that. From the standpoint of information exchange, I think it's technological, and that's what we're working on.

PJM already has a common portal called CSS that works to some extent, and allows one-stop shopping on certain functions between PJM and New York. New York is implementing a complementary system that will make New York and PJM's market participants have one-stop shopping, and when they want to do transactions between New York and PJM, it will confirm those transactions. We can't do that today, but late this year when the New York software goes in, we'll then be able to have those two systems completely interact, and they will confirm the transactions, and no one will have to go in Mike's web page or my we page to do that.

Then we're going to continue to evolve that. We don't have any legal or programmatic problems in exchanging the data right now. Our MMUs have similarly. They get together; they don't have any problems in that regard.

MR. ROGERS: One other thing, to follow up on your offer to make quarterly filings with the Commission, updating us regularly on progress in resolving seams, is that something you'd be willing to follow up with, presentations to the Commission, if the Commission desired that?

MR. MUSELER: We certainly would, if that's what the Commission wanted us to do.

CHAIRMAN WOOD: We'll give you a time-certain next time.

MR. ROGERS: Would the Commission like those reports to reflect stakeholder and state commission input on an ongoing basis?

CHAIRMAN WOOD: I'm assuming, based on your representations, Bill -- I see that the items that the stakeholders and the state PUCs cared about were stuck in these documents. I'm looking at really the Seams Action Plan as new. l

MR. MUSELER: Yes, the ones that were added were added as new. I should point out that there were a fair number of comments. Probably the largest number of comments were that people wanted these projects done sooner than scheduled.

So, I don't want to represent that this schedule represents something that the PUCs agreed to every scheduled item on there, or that the market participants agreed with every scheduled item on there.

I believe we've captured all of the items.

CHAIRMAN WOOD: The items that are on there, it's the sequence and timing that is still kind of in play.

MR. MUSELER: We frankly don't see how we can meet any other schedule than this right now, given the commitments and the three ISOs that are in major market improvements that are going on in parallel.

MR. ROGERS: Mr. Chairman, I might recommend that we allow the opportunity for interested parties to file comments on these quarterly reports when they are made.

CHAIRMAN WOOD: I think that gives them some feedback, but also helps us know a lot more, up close, what the issues are. Again, I'm going to go spend some more time on this, since I just got it last night, and I think we'll probably have some followup questions, and we'll just contact you all.

Then we'll sit in here in maybe about three months and check on the progress.

COMMISSIONER BROWNELL: Could I just ask for an addition to this report? And I would appreciate it. I'm glad to see all those lovely blue lines, and that we're completing tasks. That's a good thing, but I don't know if those were completed on the original timetable.

If we really want to stay on top of this, I think we need to know, on a regular basis as part of this report, what were the original target dates and what was the final completion date.

To the extent that things are sliding, that would be where I would focus my energies, to figure out why --

MR. MUSELER: That's a very good suggestion. For the projects that are not done, we will freeze those dates. If there's a revised date, we'll indicate it or call it a revised date, and leave the original date on there, so you can see if anything slips.

COMMISSIONER BROWNELL: And you'll add these new issues to this list.

MR. MUSELER: We've probably got most of them, although we've got some of the filings that were made to you pretty late. I would suggest that we won't change any of the due dates that are on here, but we may at this point, rather than waiting another three months, if, within the next week we pick up any additional items, we'll just forward that to you, but we won't change any of the projected dates on here.

And we will, to the extent, between now and October, that we actually get scheduled dates -- there are actually six items on here that don't have dates -- to the extent we get dates for those, once we research them and know exactly what we have to do, we'll provide those dates.

COMMISSIONER BROWNELL: Is there a process whereby you're having some dialogue with your stakeholders about their disagreement with implementation dates?

Is there an opportunity to maybe re-prioritize according to market needs?

MR. MUSELER: There's certainly an opportunity, and I'll let Mike and Dave speak for their stakeholder processes -- there's certainly an opportunity. In fact, in New York, the stakeholders have a project priority process, which is the leadership of all the major committees and the ISO prioritize the projects.

If there are any schedule changes, those are made generally on a consensus basis. There is that process.

What we don't have -- and that's one of the things the CEOs want to talk about, because we don't feel that it would be productive, is to go to what I'll call a communal stakeholder process. That's what we had under the MOU.

We had meetings of about a hundred people to try to prioritize the seams issues, decide what the detailed conceptual design of the fixes were going to be, and we got, frankly, nowhere with that.

The results we've gotten, we've gotten through a

Kissinger-like shuttle diplomacy. The stakeholders have never been cut out of this process, but we've essentially been able to do is either in groups of two of us, who are responsible for a given seam or sometimes a larger group of the ISO staffs, we've gotten together and come up with proposed solutions that we have been individually taking back to our own stakeholder groups and fought it out at that juncture.

And sometimes we've had to go through an iteration as a result of that process, but we have at least been able to make progress that way. So we're leery.

I can't predict what all of the CEOs are going to decide on this, but at least those of us that have been through that process -- Phil Harris and I talked about it last night -- really don't believe that a global stakeholder process on this, at least at this juncture -- there may be the need for it in the future, but at this juncture, we're really worried that might bring us back to what we went through during the MOU days and stymie the process rather than help it.

But stakeholders, believe me, have input, and they're not shy.

COMMISSIONER BROWNELL: Is there any attempt ever to prioritize by cost, either costs that could be wrung out of the market and should be looked at earlier, rather than later? Or costs that might be incurred by the market? That might be a flip side of the same thing, because these are barriers. Can you do that?

MR. MUSELER: I'd have to say not on a rigorous basis, but on a judgmental basis, yes, we absolutely do that. But we don't have a formal let's get the costs of implementation against the benefits to the market.

But there are some things that are clear. If we have checkout procedures that are resulting in a five-percent rate of transaction failures, and there is room on the interface, that would be something that we would put right up front.

COMMISSIONER BROWNELL: Thanks.

CHAIRMAN WOOD: Steve, gentlemen, thank you all very much for coming and waiting so long. We appreciate the work you all are doing. Our final item?

SECRETARY SALAS: A-3, Western Market Infrastructure Reform, with a presentation by David Langenfelder, Camilla Ng, Brian Harrington, Meesha Bond, and Jeff Wright.

CHAIRMAN WOOD: While you all are walking up here, I want to say that I've read the long version. It is so well done. I'm so proud of the workproduct here.

This is exactly the start that I love. I'm so proud of what you're doing, and look forward to your standing up and taking a well-deserved bow.

(Laughter.)

MR. LANGENFELDER: Thank you for that. I would start with thank you and good afternoon. Thank you for letting us present or study. I'm David Langenfelder with the Office of Market Oversight and Investigation.

Our team has prepared an Western Market Infrastructure Assessment. The assessment highlights the factors affecting current and projected electric availability.

(Slide.)

MR. LANGENFELDER: And prices in the Western United States. We have select members from the team with us today to briefly present our findings.

To my right is Camilla Ng. She will address the western electric and natural gas spot prices. Brian Harrington will address the electric supply and demand, along with the electric infrastructure additions that have, till today, taken place in the West, and what's projected. Meesha Bond will address the Western electric transmission grid, and Jeff Wright will address the natural gas supply and demand in the Western markets. Next slide, please.

(Slide.)

MR. LANGENFELDER: Looking briefly at the economic conditions surrounding the western markets, population and economic growth in the West were highest in the states bordering California from 1995 to 2000.

During this time, population growth was greatest in Nevada and Arizona, and these states, as well, shared in robust economic growth. Starting in 2001, all the western states experienced an economic slowdown, contributing to a decline in electric and gas demand. While this economic slowdown has suppressed demand for natural gas and electricity across the western markets, it is unlikely that this will continue.

Through 2010, growth estimates for population and retail electric sales are projected to be at the highest in the states bordering California once again.

(Slide.)

MR. LANGENFELDER: Now, turning to the challenges facing the western credit markets, this map identifies the creditworthiness of investor-owned utilities and their associated service territories. On the map, it appears orange, but in the printed document, it's red.

The red region reflects the service territories in the western markets who are currently rated at junk-bond status by Standard and Poores. Yellow reflects companies that are on a credit watch, but are of investment grade.

And the blue represents companies that are listed as stable and are of investment grade. The yellow is actually green. However, this map does not reflect the credit crunch that has been squeezing the merchant generating sector of this industry.

The industry's current credit rating downgrades have limited the number of credit-worthy counterparties for transactions. With bond rating downgrades looming and stock prices for this sector slipping some 80 percent in the past year, it is clear that capital expenditures will be cut, leaving many plant expansions tabled or cancelled, thus impairing infrastructure development across the West. Camilla Ng will continue with the electric and natural gas supply crisis.

MS. NG: Next slide, please.

(Slide.)

MS. NG: This slide shows the prices for electricity in the western trading hub from January 2000 through July 2002. The dashed red line represents the various market mitigation measures enacted during this timeframe. As you can see, the market exhibited extreme volatility from June 2000 through June 2001.

As price mitigation measures were applied specifically to California from June 2001 to present, the prices have stabilized. Factors contributing to price stability were economic slowdown, favorable weather in 2001, improved hydro conditions, lower natural gas prices, more generating capacity coming on line across the West, and the

Commission's West-wide market mitigation from June 2001 onward.

Last week, spot prices surged at extremely high temperatures, soaring across the West. Although the Northwest continued to have ample hydropower supplies, and Bonneville Power Administration continued to offer 700-800 megawatts of surplus power, the derating of the California-Oregon Intertie and the Pacific BC Intertie hindered the flow of electricity southward to California.

In addition, the unexpected loss of 2200 megawatts of power in California increased the total outages on July 9th, compounding the problem of the heat wave. This caused the California ISO to shed load through interruptible contracts on July 9th and 10th.

The California ISO issued consecutive Stage I and II emergency alerts, as operating reserves slipped below required levels. This resulted in a recalculation of the price cap to a low $55.26 per megawatt hour.

Concerns that the low price cap could cause severe supply disruptions, on July 11th, the Commission restored the earlier cap of $91.87, and fixed it as a hard cap through September 30, 2002.

The latest breaking news today: Northern California prices rose over $5 this morning, on expectation that forest fires in the region will reduce imports from the

Pacific Northwest. Deliveries on high-voltage transmission lines from Oregon may be cut by more than two-thirds due to forest fires, in addition to the loss of a transformer in Montana this morning, that has cut power exports to California.

However, later on, BPA said plans to shut down transmission lines were cancelled on two coming days. BPA said that it will keep power flowing tonight. Next slide, please.

(Slide.)

MS. NG: This slide shows natural gas spot prices at western trading hubs, compared with the national average from January 2000 through July 2002. The market exhibited extreme volatility from November 2000 through June 2001. However, from June 2001 to present, prices have stabilized.

Western gas prices tracked the national average closely from August 2001 to the present. Factors contributing to price stability were lower electric demand due to economic slowdown, greater hydroelectric supplies, moderate weather last summer and winter, gas glut in the Rockies and Canada, and substantial natural gas storage inventory.

Last week during the heat wave in the region, the region supported strong gains on natural gas spot prices, as demand for gas-fired generation increased due to the soaring cooling load. Topock prices increased ten percent over the national average. That was about $3.20, and the national average was $2.90.

Brian Harrington will continue with the electric supply and demand. Next slide, please.

(Slide.)

MR. HARRINGTON: Good evening. I'll forewarn you first that the second side I'll use takes about five minutes, so bear with me as I go through it.

In the next four slides, I will discuss reserve and operating margins for the period 2000 through 2003; plant additions placed in service through May 2002; anticipated additions to come into service through 2005; and projects that have been cancelled and put on hold through May 2002.

Moving to the first slide, reserve margins reveal an amount of unused, available capability in the electric power system and serve as a barometer for identifying demand and supply imbalances. Adequate reserve margins enhance reliability and foster competition, while low reserve margins send signals for needed infrastructure, and/or increased conservation efforts.

According to a recent study by the Cambridge Energy Research Associates, reserve margins in the WECC were the lowest of all the regions in 2001. You will see in the next slide that reserve margins are improving.

(Slide.)

MR. HARRINGTON: However, operating reserve margins remain tight in all western subregions except for the Northwest Power Area, due to their abundant supply of generation and improved hydro conditions.

(Slide.)

MR. HARRINGTON: As we go into the next slide, the key thing is the operating reserve margin. This provides a snapshot of the supply and demand conditions during the peak hour of each month from January 2000 to January 2004.

The data presented is based upon non-coincidental peaks, and should be considered as representative, rather than definitive, since different patterns of demand and generation cause variations in reserves and operating margins on a day-to-day or hour-to-hour basis.

Even though trade between subregions is encouraged and is a function of competitive markets, we did not include imports and exports in our data. We wanted to highlight the four western subregions on a stand-alone basis.

I will briefly explain the graphs in each corner, and then discuss each of the region's reserve and operating margins.

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You can look at any one of the graphs. The black line shows total resources. That's going to be the one on the top of any of the graphs. The yellow shaded area, which is the green, is the available resources.

This accounts for forced outages, scheduled maintenance, and inoperable capacity, and the pink line --

CHAIRMAN WOOD: You said it's forced outages.

MR. HARRINGTON: Scheduled maintenance and inoperable capacity.

CHAIRMAN WOOD: Would the last one be hydro that doesn't have water behind the dam or what?

MR. HARRINGTON: There's a little hydro derate in the total resource number.

CHAIRMAN WOOD: Okay.

MR. HARRINGTON: If you look at the Northwest Power Pool, you can see a little dip in capacity in the black line. It's very little.

The reserve margin is the difference between the black line total resources and the pink line, peak demand, whereas the operating reserve margin, the measure for keeping the lights on, is the difference between the yellow shaded area, available resources, and the pink line, peak demand.

You will see that the reserve and operating margins vary amongst the four western regions, with Arizona, New Mexico, and Nevada, having the lowest, followed by California and Mexico.

Let's turn our attention now to the Northwest power graph in the upper left-hand corner. As the graph shows, there's an abundant supply of resources compared to the level of demand.

Both available resources and total resources far exceed the peak demand. Hydroelectricity is a golden asset. California and others have for years relied upon these supplies to meet demand during peak times, or to displace higher-cost generation with cheaper power.

Under normal hydro conditions, the Northwest power area can generate hydro capacity for several more hours than when conditions are below normal or become adverse.

The 2000-2001 water year was the second lowest water year the Northwest has experienced since recordkeeping began. For comparison, the Northwest power area generated approximately 220 million megawatt hours in 1999, a normal hydro year, as compared to 130 million megawatt hours in 2001, an adverse hydro year.

In percentage terms, this was a 40-percent decline. This goes back, Pat, to what you were talking about, the hydro in the graph; the graph does not capture the severity of this decline, because it's the duration of hours, not the capability that is most affected by hydro conditions.

CHAIRMAN WOOD: Would there be an assumption then that when you look at the yellow/green part of the graph, is there an assumption that that hydro capacity is actually almost fully available at peak? It's just that the valleys are a lot deeper.

MR. HARRINGTON: If you're talking about a short period of time, yes. If you're talking eight, ten hours, 12 hours, it's different, especially during adverse hydro conditions.

CHAIRMAN WOOD: Okay.

MR. HARRINGTON: Additionally, the water flow associated with hydro power resources must balance several competing interests, including, but not limited to: electric power generation, flood control, biological requirements, as well as special river operations for recreation, irrigation, navigation, and refilling of the reservoirs in each year.

Balancing these interests is challenging and can become quite difficult when hydro conditions are not favorable. This year, hydro conditions have improved, but the reservoir levels still remain below normal.

With the threat of El Nino returning, regional hydroelectric supply may be adversely affected. California and others who rely upon the imported power must realize that hydro conditions change, and adverse conditions may reoccur.

Bottom line: There are no guarantees. Let's now move on to the California-Mexico graph in the bottom left corner. Summer operating reserve margins, excluding imports, for 2000 through 2002, reflect that inadequacies exist with available generation, and that imports are relied upon to meet operating reserve requirements and peak demand.

Looking at total resources, the black line, California has a comfortable spread over demand, the pink line. However, as the chart shows, a good chunk of this capacity is not reliable and available when needed.

On the graph, this would be the shaded green area, as compared to the black line. Much of this has to do with the age of the units, environmental restrictions, and the fleet of high-cost, less efficient, gas-fired peaking units. Their fleet of plants is approximately 60,000 megawatts, and of this, approximately 35,500 megawatts are 20 years old or older.

In percentage terms, this accounts for 60 percent of those plants. Of that, approximately 16,000 megawatts are less efficient, gas-fired units. Even as new generation comes online, they are really only displacing their less efficient units with more efficient units.

As demand outstrips new supplies or imports become unavailable, California may have to rely upon those who own less efficient gas-fired units again. California needs to be cautious of the growing populations occurring in major cities outside of their state.

The bottom line is: Regional demand is and will continue to change, which places additional pressures on California's position to use imported power, rather than to build new generation -- enough new generation within the state to meet periods of high demand.

An additional problem that California faces is restricted gas supplies. Since all new generation coming online is gas-fired, with a few exceptions, demand for natural gas will increase.

As greater reliance is placed on gas-fired generation, or peaks for electric and gas supplies occur simultaneously, California may find itself short of needed gas supplies. Combine this with an adverse hydro year, and California may face another power crisis like they experienced in 2000.

Let's now move to the Arizona-New Mexico-Nevada graph in the bottom right corner. Quite simply, demand has hit supply. The increasing population and growing business economies are fostering this rapid rise in demand.

Those neighboring states such as California that rely upon imports from this region should expect no more imports than they are currently receiving and may experience a reduction, unless they are willing to pay higher prices than those consumers within the Arizona-New Mexico-Nevada region or other regions.

Operating in reserve margins, not considering imports, have been negative or slightly positive for the past three years during summer peak. Looking at the graph, you can see that the available resources, the green shaded area, is below peak demand, the pink line, from 2000 to 2002.

And the total resources, the black line, is just hovering peak demand during summer months for the same period. Looking at the map in the middle, you see Arizona, New Mexico, and Nevada, summer 2002 operating reserve margin is negative 2.9 percent, and, again, it does not include imports or exports.

This suggests that potential power emergencies may occur throughout the rest of the summer. However, the outlook for next summer looks much brighter, as the region expects an additional 8500 megawatts to come online to meet peak.

Referring back to the graph, you see that the yellow shaded area and the black lines move up considerably from peak demand line in 2003.

Let's now move to the Rocky Mountain Power Area graph in the upper right corner. The region contains the least amount of resources of the four subregions.

In 2000 and 2001, the resources were closely tracking peak demand. However, as we move into summer 2002 and 2003, additional capacity coming online will yield some breathing room for this region.

Overall, in the four regions, reserve margins are improving, however, the operating reserve margins remain tight for this summer. As we approach next summer, both reserve and operating margins are expected to improve due to the generation that is currently under construction and anticipated to come online by next summer.

(Slide.)

MR. HARRINGTON: The next slide provides a breakdown of the capacity regions by region and status. Ninety-five percent of the new generation entering western markets is and will be fueled by natural gas.

The map on the left illustrates that new plants are being located within close proximity of major natural gas pipelines. The chart to the right shows the status of new generation that is in operation, under construction, or advanced development.

To date, approximately 11,000 megawatts have come online in the WECC. These megawatts are identified in blue, I guess. They're at the very bottom.

Leading this effort is the California-Mexico region with 4,552 megawatts. Looking ahead, several thousand megawatts are in the under-construction phase in the Arizona-New Mexico-Nevada region, and the California-Mexico region.

As the 2002 operating margins reflect in the previous slide, these additions are crucial for meeting future peak demand. However, under current market conditions, there is no guarantee that megawatts currently under construction or in the advanced development phase will be carried out or brought online within the anticipated timeframes.

You will see in the next slide, that several projects have been cancelled or tabled.

(Slide.)

MR. HARRINGTON: Lower spark-spread outlooks, thinner profit margins, and industry uncertainty have diminished the incentive to build new power plants.

Fifty percent of the tabled and cancelled projects have occurred in California, for the reasons stated above, plus, investors are concerned about the lack of stable market rules in California, and the potential that long-term contracts may be renegotiated.

Just in the past six months alone, since December of 2001, 27,000 megawatts throughout the WECC have been cancelled or put on hold. That's 64 percent of the total cancelled projects.

This strongly suggests that additions anticipated to come online over the next 12-24 months may change. The unknown is, how much or what effect this will have on the estimated reserve and operating margins for next summer.

This concludes my section of the presentation. Meesha Bond will continue with transmission infrastructure.

(Slide.)

MS. BOND: Thank you. The western transmission system is distinct in that it was designed to carry power over long distances. The western area also has a mix of summer and winter peaking areas.

This combination has resulted in a symbiotic relationship of power sharing. The Pacific Northwest is winter-peaking and California is summer-peaking. Next slide.

(Slide.)

MS. BOND: And in the summer, the Pacific Northwest would sell power to California. In the winter, California would sell power to the Pacific Northwest. If you look at the transfer capabilities of the various western regions, you will see that each region has an equivalent import and export capability, with a few exceptions, such as

California. California can import more than it can export.

Also, if you notice, California is approximately 10,000 megawatts of import transfer capabilities from the Northwestern Power Pool. That includes, in ideal situations, 5,000 megawatts at the California-Oregon border; 3,000 megawatts at the Pacific-DC tie-line going into Los Angeles; and approximately 2,000 megawatts of the Intermountain Project in Utah that comes into southern California. Next slide.

(Slide.)

CHAIRMAN WOOD: Tell me again, Meesha, the big long, DC tie from the North?

MS. BOND: The actual numbers: California-Oregon border is 4,880 megawatts on the specific DC tie-line. It's 2,990 megawatts coming from the Intermountain Project in Utah; it's 1,920 megawatts and the two others are the Desert Inter-ties with the 160 megawatts and 18 megawatts.

CHAIRMAN WOOD: Is that what you're showing with the little white boxes, or is this in addition to that?

MS. BOND: It's the ones in the little white box.

CHAIRMAN WOOD: You really just have a little one-way arrow on the bottom; is that right?

MS. BOND: That's the Palo Verde coming in from the nuclear plant; that's 7,550.

CHAIRMAN WOOD: Okay.

(Slide.)

MS. BOND: This slides shows the transmission constraints in the West and the high electric spot prices at the hubs. You notice that spot prices increase as you travel further South.

The price differential can be caused by several things such as seasonality, gas prices, or transmission constraints. The constraints on Path 65 or 66 keep inexpensive power from flowing south to California.

The transfer capabilities can also limit power flows as well, and in June as well as in July, the wildfires that have been at the California-Oregon border have caused the inter-ties to be decreased. Currently, as repairs have been going on, CB is only at a limit of 3,200 megawatts, as opposed to their idea of 4,880. We also have a derating on the DC tie-line. It currently is only at around a little bit over 2000.

This can also affect reliability in the area, as you are unable to import the power that's needed to relieve the congestion, and also to meet the demand. Now, I'll be turning the presentation over to Jeff Wright.

MR. WRIGHT: Thank you. Looking at the gas markets, next slide, please --

(Slide.)

MR. WRIGHT: Looking at the gas markets in the

WECC, gas consumption at commercial, industrial, and residential electric generation sectors in 2001, it totaled about 2.4 Bcf, about 20 percent of total U.S. gas consumption. California accounts for about over half of the WECC's gas consumption, about 56 percent.

Rapid population and economic growth in states bordering California has caused an increase in gas consumption that has historically been available for delivery to California. Electric generation, which I will guess is in yellow -- I'm the color-blind guy -- is the dominant consumption sector in California and in the Arizona-New Mexico-Nevada subregion.

For the entire WECC region, over 38 percent of the gas consumed is for electric generation, and we can expect electric generation's proportionate consumption to increase as more gas-fired electric generation comes online in the near future. Next slide, please.

(Slide.)

MR. WRIGHT: As Brian mentioned, 95 percent of new electric generation in the WECC will be fueled by natural gas. Looking just at those generation facilities that are under construction, and in the advanced development stage, it shows an increased gas demand for new electric generation load of almost 2.9 Bcf per day by they year 2005.

The most striking increases in the Arizona-New

Mexico-Nevada subregion, which is experiencing large growth in load centers such as Phoenix and Las Vegas, as shown on the map, new generation outside of California is located on or near interstate pipeline facilities. This increased load will necessitate the expansion of the interstate pipeline system, especially in the Southwest.

As an aside to gas demand, if you look nationwide, good counts in the U.S. have dropped from 1300 in mid-2001, to just over 700 this week. This would indicate that the gas market is heading into a bust cycle.

When demand does rebound, prices in the U.S. and necessarily in the western U.S. region can be expected to rise as supply tries to keep up. Next slide, please.

(Slide.)

MR. WRIGHT: This slide shows pipeline utilization in the four WECC subregions by comparing capacity, as represented here by coincidental peak-day use in each subregion, with the average daily flow of gas. This emphasizes the high utilization of pipeline capacity in the Southwest and up to the California border.

This level of utilization also includes the addition of the Kern River capacity that was the subject of Item C-5 earlier in today's agenda; that is, Kern River added no new slack capacity in the West. All the capacity was contracted for.

As shown in the previous slide, the majority of new gas generation is being located in California and in the Arizona, New Mexico, and Nevada subregion. Without adequate infrastructure additions along traditional routes in the Southwest, or from new routes from the Rocky Mountain Region, the ability to serve new generation load will be greatly impaired.

During our study, we have observed that operating reserve margins are low in the WECC, especially in the Arizona, Nevada, New Mexico subregion. The constrained electric transmission system in the Western U.S. limits the import and export of electricity between the regions.

California continues to rely heavily on electric imports to meet its demand, and at the same time, there's above-average population and economic growth in the Southwest and Northwest, which will necessarily limit available exports to California.

California and the Northwest are heavily dependent upon generation from hydroelectric sources, making them open to draught-related generation deficits, and there is a heavy dependence upon natural gas to fuel new electric generation that is being developed in the western U.S.

It is not clear that the current pipeline grid and traditional areas of gas supply will be able to meet growing demand. Further increases in the region's economy will increase current gas load, threatening the reliability of the gas infrastructure to meet the new market demand. Next.

(Slide.)

MR. WRIGHT: In conclusion, given the current western U.S. infrastructure, there does not appear to be enough excess capacity to support a fully-competitive market during periods of peak demand.

The western energy markets are susceptible to disruption with the occurrence of one or more events such as accelerating economic growth, widespread high temperature and/or low precipitation, resulting in lower reliability and volatile prices.

Finally, energy infrastructure expansion, we believe, is needed for competitive energy markets in the western U.S. That concludes our presentation, and we're available for any questions.

CHAIRMAN WOOD: A fine presentation, at that. I mean, it; that was very good, and the work underlying it was superior. It set a high bar. I wish it was a happier story, but, you know, we can't fix things unless you know there's something wrong. That's a clarion call, if ever I heard one. Madam Commissioner?

COMMISSIONER BROWNELL: This is terrific. You guys are getting really good at this. I want to go back and start now with all the other regions of the country and redo those.

I think this is probably the most critical kind of information we can be getting, in addition to what our market monitoring group is going to be doing. It would seem to dance on the head of a pin, but this one is not ours to fix.

CHAIRMAN WOOD: No, the more we talk about it, the more other people start to care. That's the point of road shows, in case people are missing the connection there.

At the risk of prolonging a long day, I will just say what a great way to end it, with this kind of work product. I appreciate the standard you all are setting for the rest of our wonderful FERC family here of excellence. Keep up the good work. Have a good evening. Meeting adjourned.

(Whereupon, at 6:25 p.m., the meeting was adjourned.)

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